Petition for Approval of Divestiture Transaction

August 1998

Commonwealth of Massachusetts
Department of Telecommunications and Energy
Docket D.T.E. 98-83

Volume 1 of 3

Eastern Utilities
Eastern Edison
Montaup Electric

Eastern Edison Company
and
Montaup Electric Company

Filing for Approval of Divestiture Transaction

VOLUME I

Cover Letter

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August 7, 1998

VIA HAND DELIVERY

Mary Cottrell, Secretary
Department of Telecommunications and Energy
100 Cambridge Street - 12th Floor
Boston, Massachusetts 02202

Re: Montaup Electric Company and Eastern Edison Company, D.T.E. 98-83

Dear Secretary Cottrell:

Enclosed for filing are the following:

1. Petition by Eastern Edison Company ("Eastern") and Montaup Electric Company ("Montaup") pursuant to the terms of the Restructuring Settlement approved by the Department in Docket D.P.U./D.T.E. 96-24, and G.L. c. 164, § 76 for Montaup to sell to Southern Energy New England, L.L.C. ("Southern") its interest in the Canal 2 generating facility.[1]

2. Motion to Consolidate Montaup's divestiture proceeding on the sale of Montaup's interest in Canal 2 with the divestiture proceeding of Cambridge Electric Light Company, Commonwealth Electric Company, and Canal Electric Company ("Canal"), which is a joint-owner of Canal 2.

[1] On July 15, 1998, Southern entered into an Assignment Agreement with Southern Energy Canal, L.L.C., whereby Southern assigned all of its right, title and interest in the Asset Sale Agreement to Southern Energy Canal, L.L.C.

Each of the filings is discussed below.

1. Petition by Eastern and Montaup for the sale of Montaup's interest in Canal 2.

Pursuant to the Restructuring Settlement for Eastern and Montaup that was approved by the Department in Docket D.P.U./D.T.E. 96-24 and the Federal Energy Regulatory Commission in Docket Nos. ER97-2800-000 *et al.*, Montaup committed to divest its generation business. This petition implements that commitment.

On May 15, 1998, Montaup agreed to sell and Southern agreed to purchase Montaup's fifty percent interest in Canal 2, a generating facility in Sandwich, Massachusetts (the "Divestiture Transaction"). The Divestiture Transaction was part of a joint marketing and sales effort with Canal, owner of the remaining fifty percent interest in Canal 2 and the operator of the facility. Southern has agreed to pay Montaup $75,102,000, or approximately two times the net book value of its interest in Canal. Copies of the agreements pertaining to the Divestiture Transaction are included with the Petition.

The Department has jurisdiction and authority to review and approve the Divestiture Transaction under the express terms of the Settlement and under its authority to supervise electric companies (G.L. c. 164, § 76). Pursuant to the Settlement and the standards set forth in G.L. c. 164, §1A(b)(1), the method of the sale of Canal 2 and the proceeds of the Divestiture Transaction should be deemed reasonable. More particularly, this filing demonstrates that the joint marketing team employed a "competitive auction or sale" that ensured "complete, uninhibited, non-discriminatory access to all data and information by any and all interested parties seeking to participate in such auction or sale." G.L. c. 164, § 1A(b)(2). *See Boston Edison Company*, D.T.E. 97-113, at 5-6 (1998). Additionally, the sale of Montaup's interest in Canal 2 is in the public interest, because the sale complies with the express terms of the Settlement, is consistent with the Department's procompetitive policies as expressed in D.P.U. 96-100, mitigates Montaup's contract termination charges to Eastern, and reduces Eastern's rates to its customers.

The Petition for Approval of the Divestiture Transaction also seeks a finding by the Department that Canal 2 may be designated an eligible facility pursuant to Section 32 of the Public Utility Holding Company Act of 1935. Specifically, the Department's approval of the Petition should constitute express findings by the Department that it has sufficient regulatory authority, resources, and access to books and records to exercise its duties, and that the designation of Canal 2 as an eligible facility (1) will benefit consumers, (2) does not violate state law, and (3) is in the public interest.

The Petition for Approval of the Divestiture Transaction is supported by testimony and exhibits from the following witnesses: Michael J. Hirsh, who summarizes the transaction and divestiture process; Donald T. Sena, who explains the financial elements of the transaction; and John J. Reed, who describes the joint marketing process with Canal and demonstrates that the split of the proceeds was reasonable and in the public interest. Montaup and Eastern also incorporate by reference the prefiled testimony of Michael R. Kirkwood and Frank J. Kinney, III, filed on July 31, 1998, in D.T.E. 98-78.

2. Motion to Consolidate

In this proceeding, the Department must issue an order on the sale of the Canal 2 facility and the reasonableness of the proceeds from that sale. Since Montaup and Canal jointly marketed and sold the Canal 2 facility, the Department would undergo the same legal analysis regarding the sale of the facility for each of the companies. Pursuant to 220 CMR 1.09, the Department may order proceedings involving a common question of law or fact to be consolidated for hearing on any or all of the matters in issue in such proceedings. Since the sale of the Canal 2 facility for both Montaup and Canal involves common questions of law and fact, in the interest of efficiency, Montaup seeks to consolidate the proceedings. In the filing by Cambridge Electric Light Company, Commonwealth Electric Company, and Canal (together "COM/Electric") on July 31, 1998, COM/Electric also filed a Motion to Consolidate its proceedings with the divestiture proceedings of Montaup related to Canal 2.

Accordingly, Montaup and Eastern seek the Department's approval of the Petition for Approval of the Divestiture Transaction and the Motion to Consolidate.

Finally, enclosed herewith please find a check for $100.00, the Department's filing fee. Please note that Montaup and Eastern have included with this filing computer diskettes that contain the filing documentation. Please also note that the Companies have placed the filing on Eastern Utilities Associates Internet Web page, which can be accessed at www.eua.com. Thank you for your attention to this matter, and please call me if you have any questions concerning this filing.

Very truly yours,
David A. Fazzone, P.C.

David A. Fazzone

David A. Fazzone
Attorney for Montaup Electric Company and
Eastern Edison Company

Enclosures
cc: George B. Dean, Esq.
David L. O'Connor, Commissioner
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Eastern Edison Company
and
Montaup Electric Company
D.T.E. Docket 98-83 Service List

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Petition for Approval of Divestiture Transaction

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Eastern Edison Company Montaup Electric Company	)	D.T.E. 98-83

PETITION OF EASTERN EDISON COMPANY AND MONTAUP ELECTRIC COMPANY FOR APPROVAL OF DIVESTITURE TRANSACTION

Montaup Electric Company ("Montaup") and Eastern Edison Company ("Eastern") hereby petition for approval pursuant to the Restructuring Settlement Agreement ("Settlement") filed and approved in Docket D.P.U./D.T.E. 96-24 and pursuant to Massachusetts General Laws chapter 164, § 76 for the sale of Montaup's interest in the Canal Unit No. 2 generation facility ("Canal 2"), located in Sandwich, Massachusetts, to Southern Energy New England, L.L.C. ("Southern").[1] Montaup and Eastern also seek a determination from the Department that Canal 2 may be designated an eligible facility pursuant to Section 32 of the Public Utility Holding Company Act of 1935 ("PUHCA").

In support of the Petition, Montaup and Eastern state as follows:

1. Montaup is a Massachusetts corporation and an electric company as defined in section 1 of chapter 164 of the General Laws, and sells electricity for resale.

2. Montaup's parent, Eastern, is an electric company as defined in Section 1 of Chapter 164 of the General Laws, and provides distribution service to retail electric customers in Massachusetts.

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[1] On July 15, 1998, Southern entered into an Assignment Agreement with Southern Energy Canal, L.L.C., whereby Southern assigned all of its right, title and interest in the Asset Sale Agreement to Southern Energy Canal, L.L.C.

3. Montaup and Eastern are signatories to a Settlement that was approved by the Department in D.P.U./D.T.E. 96-24 (1997) and by the Federal Energy Regulatory Commission in Docket Nos. ER97-2800-000, *et al.* Under the Settlement, Montaup agreed to divest its generating assets.

4. On May 15, 1998, Montaup executed a contract with Southern under which it will sell its fifty percent non-operating ownership interest in Canal 2 (the "Divestiture Transaction").

5. The implementation of the Divestiture Transaction requires the approval of the Department under the express terms of the Settlement and under G.L. c. 164, § 76.

6. The Divestiture Transaction is consistent with G.L. c. 164, §§ 1A(b)(1) and (2) of the Restructuring Act, enacted on November 25, 1997.

WHEREFORE, for the reasons stated herein, Eastern and Montaup respectfully petition the Department to approve the Divestiture Transaction and make the following findings:

A. That the divestiture process to sell Canal 2 ensured complete, uninhibited non-discriminatory access to all data and information by all parties seeking to participate in the auction and therefore was equitable as required by G.L. c. 164, §§ 1A(b)(1) and(2);

B. That the divestiture process maximized the value of the generating assets for customers as required by G.L. c. 164, § 1A(b)(1);

C. That the Department has sufficient regulatory authority, resources, and access to books and records to exercise its duties, and that the designation of Canal 2 as an eligible facility, as defined in Section 32 of PUHCA (as amended by the Energy Policy Act of 1992)

(1) will benefit consumers,

(2) is in the public interest, and

(3) does not violate state law, and

D. That the Department grant any other approvals and make any requisite findings as may be necessary or appropriate in relation to this Petition.

Respectfully submitted,

EASTERN EDISON COMPANY
MONTAUP ELECTRIC COMPANY

By their attorneys,

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DATED: August 7, 1998

Motion for Consolidation

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Eastern Edison Company Montaup Electric Company	)	D.T.E. 98-83

MOTION OF EASTERN EDISON COMPANY AND MONTAUP ELECTRIC COMPANY TO CONSOLIDATE PROCEEDINGS

Pursuant to 220 CMR 1.09, Montaup Electric Company ("Montaup") and Eastern Edison Company ("Eastern") hereby move to consolidate their divestiture proceedings with the request to review and approve the divestiture of Cambridge Electric Light Company, Commonwealth Electric Company and Canal Electric Company (collectively, "COM/Electric") with respect to the sale of the Canal Unit No. 2 ("Canal 2") generation facility, located in Sandwich, Massachusetts, to Southern Energy New England, L.L.C. ("Southern").[1] Montaup and Eastern have petitioned the Department, pursuant to the Restructuring Settlement Agreement approved in D.P.U./D.T.E. 96-24 and pursuant to Massachusetts General Laws chapter 164, § 76 for the sale of Montaup's interest in Canal 2. Similarly, COM/Electric has petitioned the Department for approval of divestiture of its interests in substantially all of their non-nuclear generating facilities to Southern pursuant to the plan approved by the Department in D.P.U./D.T.E. 97-111.

In support of the Motion, Montaup and Eastern state as follows:

1. Canal Electric Company ("Canal") and Montaup each own a fifty percent interest

[1] On July 15, 1998, Southern entered into an Assignment Agreement with Southern Energy Canal, L.L.C., whereby Southern assigned all of its right, title and interest in the Asset Sale Agreement to Southern Energy Canal, L.L.C.

in Canal 2. On February 25, 1998, Canal and Montaup entered into a Memorandum of Understanding ("MOU") to jointly market and sell Canal 2. As set forth in the MOU, the joint marketing approach was designed to maximize the value of Canal 2 for Montaup and COM/Electric.

2. On May 15, 1998, Montaup and Canal executed contracts under which they will sell all interests in the Canal 2 generation facility to Southern.

3. In this proceeding, the Department must issue an order on the reasonableness of the sale and proceeds of the Canal 2 facility. Since Montaup and Canal jointly marketed and sold the Canal 2 facility, using the same experts and process, the Department would undergo the same legal analysis regarding the sale of the facility for each of the Companies.

4. Pursuant to 220 CMR 1.09, the Department may order proceedings involving a common question of law or fact to be consolidated for hearing on any or all of the matters in issue in such proceedings. Since the sale of the Canal 2 facility involves common questions of law and fact, Montaup and Eastern seek to consolidate their proceedings with the proceedings of COM/Electric. Additionally, consolidation of the proceedings will result in the efficient use of administrative resources and will allow both Montaup and COM/Electric to present their cases expeditiously and avoid duplicative discovery and testimony preparation.

5. On July 31, 1998, COM/Electric filed a similar request in its divestiture docket to consolidate its proceeding with Montaup and Eastern.

WHEREFORE, for the reasons stated herein, Eastern and Montaup respectfully request that the Department grant their Motion to Consolidate Proceedings regarding the sale of the Canal 2 generating facility.

Respectfully submitted,

EASTERN EDISON COMPANY
MONTAUP ELECTRIC COMPANY

By their attorneys,

David A. Fazzone

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DATED: August 7, 1998

EXHIBIT MJH-1

Prepared Direct Testimony of
Michael J. Hirsh

EXHIBIT MJH-1

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Eastern Edison Company Montaup Electric Company	)	D.T.E. 98-83

PREPARED DIRECT TESTIMONY OF
MICHAEL J. HIRSH

I. QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Michael J. Hirsh and my business address is 750 West Center Street, West Bridgewater, Massachusetts.

Q. What is your current position with EUA?

A. I am currently Vice President of EUA Service Corporation, Blackstone Valley Electric Company ("Blackstone"), Newport Electric Corporation ("Newport") and Eastern Edison Company ("Eastern") with the responsibility to oversee electric utility restructuring.

Q. Describe your educational and professional associations.

A. I was graduated from Carnegie Mellon University in Pittsburgh, Pennsylvania in 1976 with a Bachelor of Science degree in a double major program - Electrical Engineering and Public Policy. In 1983, I received a Master of Science degree in Electrical Engineering from Northeastern University and, in 1986, I received a Master of Business Administration degree from Northeastern University. I am a member of the Institute of Electrical and Electronics Engineers, and a registered professional engineer in the State of Rhode Island.

Q. Please summarize your business experience.

A. I have worked for the EUA System for over twenty years and during that time I have held positions in the engineering, planning and retail operations areas including Director of Resource Planning, Director of Engineering, Vice President of Blackstone Valley Electric Company and, immediately prior to my current assignment, Vice President of Technical Services. I have sponsored testimony before the Massachusetts Department of Telecommunications and Energy ("Department"), formerly the Massachusetts

Department of Public Utilities, the Rhode Island Public Utilities Commission ("RIPUC"), and the Federal Energy Regulatory Commission ("FERC").

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On May 15, 1998, Montaup Electric Company ("Montaup") entered into an agreement to sell Montaup's 50% ownership share in Unit No. 2 of the Canal Generating Station ("Canal 2") to Southern Energy New England, L.L.C. ("Southern"), a subsidiary of the Southern Company. At the same time, Southern executed agreements with Canal Electric Company ("Canal"), a subsidiary of Commonwealth Energy System, to purchase Canal's 50% share of Canal 2 and 100% ownership in Canal 1, giving Southern ownership of the entire Canal Generating Station. This joint sale of Canal 2 is the result of a joint marketing arrangement between Canal and Montaup which was developed to maximize the value realized from the two companies' divestiture of this unit. Both companies are engaged in divestiture of their non-nuclear generating resources pursuant to state-approved restructuring plans.

Montaup's sale requires approval from the Department. The purpose of my testimony is to summarize this filing, introduce the testimony of the other witnesses supporting this filing, describe the joint marketing agreement and how it was developed, and describe Montaup's plans for completing its divestiture and securing all necessary regulatory approvals.

Q. How is your testimony organized?

A. The remainder of my testimony is presented in six sections. First, I present an overview of the filing and introduce the other witnesses. Second, I summarize the terms of the sale to Southern and the associated transactions. Third, I describe the joint marketing effort that produced the agreements with Southern. Fourth, I describe the terms under which Southern will provide Wholesale Standard Offer Service to Eastern, Blackstone, and Newport. Fifth, I discuss the basis for Montaup's commitment to divest. Finally, I describe Montaup's plans for completing its divestiture process.

III. OVERVIEW OF FILING

Q. Please summarize the contents of this filing and the supporting testimony of the other witnesses.

A. The completion of the transactions needed to transfer Montaup's interest in Canal 2 to Southern requires the Department's approval. This filing describes the terms of the proposed sale, demonstrates the consistency of the overall sale transaction with the Companies' approved settlement agreement and applicable state and federal policies, including the Department's divestiture policies and the Massachusetts Electric Industry Restructuring Act (the "Act") and demonstrates the benefits of the transactions for Eastern's retail customers. Exhibits attached to the filing include all of the agreements pertaining to the sale of Montaup's interest in Canal 2 and several related transactions. These agreements are:

- Letter Agreement concerning approval by Southern's Board of Directors [Exhibit MJH-3];
- Asset Sale Agreement between Montaup and Southern, with associated exhibits and

schedules [Exhibit MJH-4];

- Wholesale Standard Offer Service Agreement between Southern and Montaup's retail affiliates [Exhibit MJH-5];
- Guaranty of Southern's parent in favor of Montaup [Exhibit MJH-6]; and
- Bill of Sale and Agreement between Montaup and Commonwealth Electric Company for the sale of switchyard transmission facilities [Exhibit MJH-7].

In addition to my testimony, this filing is supported by the following witnesses:

- Mr. John J. Reed, President of REED Consulting Group, assesses Montaup's decision to join in Canal's offering process and evaluates the reasonableness of Montaup's share of the proceeds from the sale. [Exhibit JJR-1].
- Mr. Donald T. Sena, Assistant Treasurer of EUA, presents testimony describing the benefits of the transactions to Eastern's customers. [Exhibit DTS-1].

Also, we rely on the testimony filed by Messrs. Kirkwood and Kinney in D.T.E. 98-78 describing the process by which Montaup and Canal jointly marketed Canal 2 to prospective buyers.

Q. Please summarize your testimony.

A. Montaup is committed to divest its non-nuclear generating assets under its restructuring settlement agreements, including the Restructuring Settlement Agreement ("RSA") approved by the Department in D.P.U./D.T.E 96-24 and the Stipulation and Agreement (the "FERC Settlement") approved by the Federal Energy Regulatory Commission in

Docket Nos. ER97-2800-000, *et al.* Montaup's divestiture commitment also complies with legislative mandates in Massachusetts and Rhode Island. To fulfill this commitment, Montaup proposes to sell its 50% ownership share in Canal 2 (280 MW) for $75.1 million to Southern. This sale is the result of a joint marketing agreement between Montaup and Canal, the owner of the other 50% share of Canal 2 and the remainder of the Canal Site. If approved, the sale will allow Montaup to mitigate the Contract Termination Charge ("CTC") due from Eastern under the FERC Settlement. Under the FERC Settlement, the proceeds of this sale will mitigate the CTC, which will flow through pursuant to the terms of the RSA and will result in reductions in retail rates to Eastern's customers. Through additional divestiture transactions, Montaup will sell its remaining non-nuclear assets and seek to transfer or sell its purchased power entitlements and nuclear assets.

Q. Please summarize the approvals that Eastern and Montaup are requesting from the Department.

A. In order to complete the sale to Southern and obtain the resulting savings for Eastern's customers, Montaup needs Department approval that a) the divestiture process used to sell Canal 2 ensured complete, uninhibited non-discriminatory access to all data and information by all parties seeking to participate in the auction, b) the divestiture process maximized the value of the sale, and c) the designation of Montaup's interest in Canal 2 as an eligible facility, as defined in Section 32 of the Public Utility Holding Company Act (i) will benefit customers, (ii) is in the public interest, and (iii) does not violate state law.

IV. SUMMARY OF TRANSACTION TERMS

Q. Please describe the Canal Generating Station.

A. The Canal Generating Station consists of two fossil-fuel-fired generating units (Canal 1 and Canal 2) located primarily in the Town of Sandwich, Massachusetts (units and land together, the "Canal Site"). Canal 1 is an oil-fired unit rated 566 MW which began commercial operation in 1968. Canal 2 is rated 565 MW and began commercial operation in 1976. Canal 2 was designed as an oil-fired unit, but is now capable of burning both oil and natural gas as a result of modifications completed in 1996. Canal owns the station site, all of the Canal 1 unit, and 50% of Canal 2. Montaup owns the other 50% of Canal 2 under a Joint Ownership Agreement executed in 1970. Both units are operated by Canal.

Q. Please summarize the ownership and operating agreements between Canal and Montaup.

A. Ownership and operation of Canal 2 are governed by a Joint Ownership Agreement and an Agreement for Use of Common Facilities, both executed in 1970, an Agreement of Lease executed in 1972, and a Memorandum of Understanding regarding the natural gas conversion, executed in 1993. Together, the four agreements are referred to as the "Project Documents," and are attached as Schedule 1.1(a)(37) to the Asset Sale Agreement [Exhibit MJH-4]. Canal 2 is operated by Canal on behalf of both parties and Montaup supports 50% of the cost and is entitled to 50% of the production. Montaup has certain rights regarding improvements, operating decisions, and sale of Canal's interest, as described in the Project Documents.

Q. Please summarize the transaction between Montaup and Southern.

A. Southern will purchase Montaup's 50% ownership share in Canal 2 for $75.1 million, assuming all of Montaup's rights and obligations under the Project Documents. This sale price is contingent upon closing by November 15, 1998. In addition, Southern will assume responsibility for supplying a share of Montaup's wholesale Standard Offer Service responsibility to Eastern pursuant to the RSA and the FERC Settlement. These responsibilities are described more fully below.

Q. Is Southern also buying Canal's interest in Canal 2?

A. Yes. Under the joint marketing process conducted, Southern submitted a bid on, and was awarded, the entire Canal Site. It has executed separate agreements for purchasing the Montaup and Canal interests in the Canal Site.

Q. Please elaborate on the November 15, 1998 contingency.

A. Under the terms of the Asset Sale Agreement between Montaup and Southern, if the closing does not occur by November 15, 1998, then the purchase price may be adjusted downward by $150,000 per month, up to a maximum adjustment of $750,000.

Q. Is a closing of the sale of the Canal interest in the Canal Site a condition of closing Montaup's sale in Canal 2?

A. Yes. Section 8.1(f) of the Asset Sale Agreement [Exhibit MJH-4] states the closing with Canal shall have occurred or shall occur concurrently as a condition of closing the Montaup transaction. The Canal Asset Sale Agreement includes an identical condition relating to the closing on the Montaup interest in Canal 2.

Q. Please describe the disposition of Montaup's existing power sales contracts associated with Canal 2.

A. Montaup entered into an agreement, effective November 1, 1988, with Taunton Municipal Lighting Plant ("Taunton") to exchange 10MW from its share of Canal 2 for

15MW of Taunton's Cleary 9 unit. In addition, Montaup entered into a similar exchange arrangement with Braintree Electric Light Department ("Braintree"), also effective November 1, 1988, under which Montaup exchanges 25MW of its Canal 2 capability for varying amounts of Braintree's Potter 2 unit. Each of the arrangements has a term extending to the earlier of the end-of-life of Canal 2 or the exchange unit, unless terminated earlier by mutual agreement. The purpose of both of these exchanges was to improve the parties' generation mixes and reduce their power supply costs. In connection with Montaup's sale of Canal 2, the parties to the exchange arrangements have agreed to terminate the exchanges by mutual consent.

Q. Will Montaup be selling any of its ownership interests in the transmission facilities at the Canal Generating Station?

A. Yes. All of Montaup's ownership interests in transmission facilities at the Canal Site will be transferred at Montaup's book value to Commonwealth Electric Company under an agreement between the two companies [Exhibit MJH-7]. This transaction is explained in the testimony of Donald T. Sena. [Exhibit DTS-1]. Southern will be buying, from Canal and Montaup, those station and switchyard facilities classified to the generation function and needed to interconnect the Canal units to NEPOOL Pool Transmission Facilities ("PTF") at the Canal Site. FERC has exclusive jurisdiction under the Federal Power Act over the disposition of these transmission and switchyard facilities.

V. JOINT MARKETING AGREEMENT

Q. Please describe the terms under which the joint marketing of the Canal facilities was conducted.

A. The joint marketing was conducted pursuant to a Memorandum of Understanding ("MOU") between Canal and Montaup executed on February 25, 1998 [Exhibit MJH-2]. Under the MOU, Canal and Montaup agreed to join in marketing their interests in Canal 2 through the process being conducted by Canal and its financial advisor, Goldman, Sachs & Co. ("Goldman"). The MOU describes how the proceeds from the eventual sale are to be allocated to the parties and the terms by which the parties would work together during the marketing process. The MOU allowed the entire Canal Site to be sold to a single buyer in one transaction.

Q. Why did Montaup agree to a joint marketing process?

A. By joint marketing, Montaup sought to obtain the maximum value for the sale of its interest through the divestiture process. This point is further discussed by John Reed in his testimony [Exhibit JJR-1]. Maximizing the sale value of the unit provides the greatest possible reduction to the CTC that Montaup's customers are obligated to pay and the greatest possible benefit to Eastern's retail customers.

Q. Was Canal's auction process already underway when the MOU was executed?

A. Yes. Canal had completed the non-binding first round of bidding and was in the process of evaluating the proposals it had received.

Q. Was the auction process being used by Canal and Goldman comparable to the process that Montaup had proposed to the Department, RIPUC, and FERC in its previous filings?

A. Yes. Canal and Goldman were employing an identical method to the one that had been proposed by Montaup and its affiliates in filings with the Department in D.P.U/D.T.E 97-105, the RIPUC in Docket No. 2592, and in an informational filing to FERC on July 1, 1997. Montaup's and Eastern's divestiture plans were updated in a supplemental filing in

D.P.U./D.T.E. 97-105 on November 21, 1997. These filings are described in Section VI of my testimony.

Q. Please describe how the joint sale was integrated into the Canal process.

A. The testimony of Michael R. Kirkwood [Exhibit MRK-1 in D.T.E. 98-78], describes in detail the process used. In summary, after the MOU was executed, Goldman contacted qualified potential bidders identified by both Canal and Montaup and notified them that bids for the Canal Generating Station would be accepted only for the entire Canal Site, and only through the Canal process. All bidders who had previously been qualified to participate in bidding for either the Canal or Montaup share of the Canal Site were given the opportunity to submit a bid for the entire Canal Site.

Q. Please discuss how the allocation of proceeds between Canal and Montaup was determined.

A. While bidders were evaluating the Canal Site as an integrated unit, they were in fact bidding on two very different ownership interests. Montaup owns 50% of a generating unit on the site (Canal 2) along with specific interests in certain common facilities and 50% of the gas pipeline, and has certain rights with regard to the operation of Canal 2 and use of the related facilities as specified in the Project Documents. Canal owns the remaining generation, transmission, common facilities and land, including development rights, and is the operator of the existing facilities. There was no objective method by which Montaup and Canal could determine what value the market would place on one interest relative to the other. Mr. Reed addresses this issue in his testimony. [Exhibit JJR-1]

Q. How, then, did Canal and Montaup arrive at the allocation specified in the MOU?

A. The allocation was a product of intense negotiations over a period of several weeks between Canal and Montaup. Montaup sought the review and advice of its advisors in its divestiture process -- Reed Consulting Group and Salomon Smith Barney -- before reaching a final agreement. Both advised that the allocation proposal to which Montaup ultimately agreed was reasonable.

Q. Please explain how the allocation works.

A. Proceeds are allocated on a sliding scale. Montaup receives the largest allocation of proceeds, 20%, for the first $200 million received for the total site. For each additional $50 million received, Montaup receives an incremental share as specified. For proceeds, if any, above $400 million, Montaup receives 10%.

Q. Were there any other adjustments to the proceeds allocated to Montaup?

A. Yes. Prior to applying the allocation, the total purchase price was reduced by 1.5% to account for fees paid to Goldman for its role in successfully designing and running the auction. Mr. Kinney's testimony [Exhibit FJK-1 in D.T.E. 98-78] describes Goldman's role and provides additional evidence that the process complied in all respects with the relevant provisions of the Act. In addition, after the allocation, there was an adjustment in Montaup's final sale price to reflect the cost of environmental commitments made by Montaup.

Q. Please explain these environmental commitments.

A. Under its Massachusetts and Rhode Island settlement agreements, Montaup is committed to meet more stringent standards for emissions of certain air pollutants at Canal 2 than are currently required by state or federal regulations. These standards take effect in 2010. Since this commitment presents a risk to the buyer and this risk applies only to

Montaup's interest in Canal 2, bidders were asked not to consider it in their bids for the Canal Site. They were informed that they would be asked to provide a separate price adjustment for this obligation during the phase-two negotiations. Montaup's final price includes an adjustment for Southern assuming this obligation.

VI. WHOLESALE STANDARD OFFER SERVICE

Q. Please describe the Standard Offer Service provisions of the settlement agreements.

A. Standard Offer Service is a feature of the state restructuring legislation and the settlement agreements designed to provide a competitively-priced source of electricity to retail customers who have not yet chosen a supplier from the competitive market. Eastern has committed to provide such service to its eligible retail customers pursuant to tariffs approved by the Department (M.D.T.E. No. 364). Under the settlement agreements, Montaup agreed to provide the wholesale power supply to enable Eastern, Blackstone, and Newport to fulfill their Standard Offer Service obligations, under fixed, escalating price terms subject to adjustment for a fuel index. The retail companies also have the right, under the settlement agreements and by operation of law, to solicit bids from alternative suppliers to provide the wholesale power supply for Standard Offer Service at prices below those agreed to by Montaup. To the extent that Montaup retains obligations to provide wholesale service for the retail Standard Offer Service, those obligations will be transferred proportionally to the buyer(s) of its divested units.

Q. Does Montaup's sale of Canal 2 to Southern involve a wholesale Standard Offer Service commitment?

A. Yes. As part of the overall sale transaction, Southern has agreed to provide 30.4523% of the full requirements of Eastern's, Blackstone's and Newport's retail customers taking Standard Offer Service, under the price and other terms to which Montaup agreed pursuant to the settlement agreements.

Q. Have Eastern, Blackstone and Newport conducted any solicitations for alternative suppliers of this service?

A. Yes. Pursuant to the settlement agreements and provisions of the Act and the Rhode Island Utility Restructuring Act of 1996, requiring Standard Offer Service to be competitively procured, Eastern, Blackstone, and Newport conducted a solicitation for wholesale power supplies in March 1998. The Companies received no conforming bids in response. As a result, Montaup has continued to supply one hundred percent of the requirements for this service. Massachusetts Electric Company and Commonwealth Electric Company have also conducted solicitations or auctions of this service, and also received no acceptable response.

Q. Do the Companies intend to conduct further solicitations?

A. Yes. The Companies plan to conduct at least one additional solicitation for suppliers of wholesale Standard Offer Service power in the fall of 1998. Any future solicitations would be limited to the share of load responsibility still remaining with Montaup (*i.e.*, "unsubscribed"), except to the extent that any agreement between the Companies and a third-party wholesale supplier contains explicit rights for the Companies to seek lower-priced bids to displace the supplier. The Wholesale Standard Offer Service Agreement with Southern [Exhibit MJH-5] contains a provision allowing the Companies a one-time opportunity prior to January 1, 1999 to include Southern's share of Standard Offer Service load responsibility in an auction and to reduce Southern's share as a result of the auction.

Q. Please describe any state findings regarding the assignment of the wholesale Standard Offer Service obligation to buyers of divested units.

A. The settlement agreements approved by the Department and by FERC include a provision for the assignment of wholesale Standard Offer Service obligations, also known as "backstop" obligations, to divested units. Additionally, the Department has affirmed that this assignment, in the context of the overall settlement parameters, benefits customers and is reasonable. In approving the settlement agreement of Eastern and Montaup in D.P.U./D.T.E 96-24, the Department found that:

> ". . . a backstop obligation does not interfere with taking all reasonable steps to mitigate transition costs to the maximum extent possible. Overall, the Department finds that [Eastern and Montaup's] mitigation plan based on divesting its non-nuclear generation, including the effect of the backstop obligation, substantially complies with the Act." D.P.U./D.T.E. 96-24, Order at 82-83.

More recently, in approving the sale by New England Power Company of substantially all of its generation facilities, the Department found that:

> ". . . the value to standard offer customers of a known price path during the transition period outweighs the potential cost of the backstop obligation. Accordingly, the backstop obligation did not prevent the Company from maximizing the value of the assets being divested." D.P.U./D.T.E. 97-94, Order at 29.

VII. THE COMMITMENT TO DIVEST

Q. Please discuss the basis for Montaup's commitment to divest its generating assets and entitlements.

A. The divestiture of the EUA System electric companies' generating business has been driven by legislative and regulatory action in both Massachusetts and Rhode Island and by restructuring orders from FERC. Each of the state initiatives, as well as FERC's action in Order Nos. 888 and 888-A, point to a realignment of the electric industry, with generation functionally or corporately unbundled from transmission and distribution. In light of this emerging structure, the EUA Companies entered into settlement agreements with parties in both Massachusetts and Rhode Island in order to resolve comprehensively the myriad issues involved in restructuring. As part of those agreements, the EUA Companies committed to the complete divestiture of their generating business.

Q. Have the settlement agreements received the necessary regulatory approvals?

A. Yes. In Massachusetts, Eastern and Montaup filed the settlement agreement among themselves, the Attorney General, the Division of Energy Resources ("DOER"), and other parties with the Department in D.P.U./D.T.E. 96-24 on May 16, 1997. The Department issued an order approving the settlement, as revised, on December 23, 1997. The companion wholesale settlement between Montaup, Eastern, the Massachusetts Attorney General and DOER, reflecting revisions as filed in D.P.U./D.T.E. 96-24, was filed with FERC as part of a unanimous settlement of the jurisdictional wholesale issues related to Montaup's all-requirements contracts with Eastern, Blackstone, and Newport, as well as its contract demand relationships with Middleborough Gas & Electric Department, and Pascoag (RI) Fire District on October 29, 1997. The wholesale settlements were uncontested. FERC conditionally approved the Companies' wholesale settlement agreements in Docket Nos. ER97-2800-000 *et al* on December 19, 1997. On January 20, 1998, Montaup made a compliance filing, satisfying FERC's conditions. FERC noticed the filing on February 4, 1998. No adverse comments were received.

Q. Please explain the Massachusetts requirements for divestiture and the applicable standards of review.

A. On November 25, 1997, the governor of Massachusetts signed into law the Act, which is designed to restructure the electric utility industry. Under the Act, utilities are required to sell their non-nuclear generation facilities to third parties or to transfer such facilities, at market value, to an affiliate. The Act provides that companies choosing to divest must "demonstrate to the [Department] that the sale process is equitable and maximizes the value of the existing generation facilities being sold." M.G.L. c. 164 § 1A(b)(1). The Act further provides that the requirement to divest shall be satisfied if the facilities are sold "in a competitive auction or sale in a process approved by the [Department] which shall ensure complete, uninhibited, non-discriminatory access to all data and information by any and all interested parties seeking to participate in such auction or sale." M.G.L. c. 164 § 1A(b)(2). Montaup and Eastern submitted their plans for divestiture to the Department in D.P.U./D.T.E. 97-105 on July 1, 1997 and supplemented their filing on November 21, 1997.

VIII. COMPLETING MONTAUP'S DIVESTITURE

Q. How are the EUA Companies proceeding with their commitment to divest their generating assets?

A. The Companies are in the process of auctioning their non-nuclear assets and power purchase agreements ("PPAs") utilizing a methodology which is substantially the same as the one filed with and approved by the RIPUC in Docket No. 2592 and filed with the Department in D.T.E. 97-105. Montaup is also continuing its efforts to divest its interests in nuclear generating facilities, pursuant to its commitment under the settlement agreements. To realize the maximum value for its assets, Montaup has joined with Canal in its sale of Canal 2 as described in this filing. The sale of Montaup's remaining assets will come before Department in D.T.E. 97-105.

Q. Does the sale of Canal 2 involve a Residual Value Credit adjustment to the Contract Termination Charge pursuant to the settlement agreements?

A. Yes. Donald T. Sena, in his testimony [Exhibit DTS-1], describes Montaup's proposed calculation of the Residual Value Credit ("RVC") associated with its multiple divestiture transactions. Montaup anticipates that a one-time filing to fix the RVC, incorporating the net proceeds from the sale of all of its generating assets, is likely to occur within the period of 90 days from the date of the first sale as allowed under the settlement agreements. [Exhibit DTS-2, Section 1.1.4(c)] However, Mr. Sena explains how multiple RVCs will be implemented in the event that Montaup's multiple divestiture transactions do not close within this timeframe.

Q. Please explain why Montaup does not simply implement a partial RVC for this sale and implement additional adjustments as other units are sold.

A. Montaup proposes to minimize the number of RVC filings and RVC rate adjustments in the interest of administrative simplicity and cost avoidance. By combining the RVCs into a single adjustment, the added administrative cost associated with multiple rate filings and rate adjustments can be avoided. Customers are not harmed by this approach since they will receive credit for carrying costs from the date of closing of any transaction at the weighted average cost of capital.

Q. Have any other agreements for the sale or transfer of other assets or entitlements been signed by EUA System electric companies?

A. Yes. On March 31, 1998, Newport executed an agreement to sell its seven diesel-fired generating units, with a total capacity of 16MW, to Wabash Power Equipment Company for $1.5 million, approximately one-and-one-half times their depreciated book value. Under the terms of the agreement, Wabash will remove the diesel units from their present sites in Jamestown and Portsmouth, Rhode Island. Since the cost of these units is included in Montaup's CTC, the proceeds from this sale will contribute to lowering the CTC obligations of Eastern.

On April 7, 1998, Montaup executed agreements with TransCanada Power Marketing, Ltd. ("TransCanada") under which TransCanada will assume Montaup's rights and obligations under power purchase agreements with Ocean State Power, a two-unit, 600-MW natural gas-fired Independent Power Producer in Burrillville, Rhode Island, in exchange for a fixed schedule of monthly payments by Montaup. TransCanada has also agreed to provide 14.4550% of the Standard Offer Service load obligations of Eastern, Blackstone, and Newport. Montaup will require FERC approval under Section 205 of the Federal Power Act in order to complete this transaction.

On June 24, 1998, Montaup executed agreements with Great Bay Power Corporation ("Great Bay") under which Great Bay will purchase, for $3.2 million, Montaup's 2.89989% ownership interest in the Seabrook Station, an 1,150 MW nuclear facility located in Seabrook, NH. Under the agreements, Montaup will pre-fund its share of the decommissioning costs of the unit and Great Bay will assume all future decommissioning liabilities. Great Bay will also provide 3.5946% of the Standard Offer Service load obligations of Eastern, Blackstone, and Newport. Montaup and Great Bay need approvals from the Nuclear Regulatory Commission, FERC, and New Hampshire and Connecticut regulatory agencies, in addition to the Department's approval of the "method of sale and reasonableness of proceeds" pursuant to the RSA, in order to complete the transaction.

Q. Does that conclude your testimony?

A. Yes.

EXHIBIT MJH-2

Memorandum of Understanding

MEMORANDUM OF UNDERSTANDING

THIS MEMORANDUM OF UNDERSTANDING is made as of this 25 day of February, 1998, by and between Canal Electric Company, a Massachusetts corporation ("Canal"), and Montaup Electric Company, a Massachusetts corporation ("Montaup").

WHEREAS, Canal and Montaup are parties to an Agreement of Joint Ownership dated as of October 27, 1970 (the "JOA"), pursuant to which Canal and Montaup constructed, own and operate an electric generating facility situated on the Cape Cod Canal in Sandwich, Massachusetts and referred to as "Canal Unit 2" ("Canal Unit 2"), each of Canal and Montaup having a 50% ownership interest in Canal Unit 2 as tenants in common on the terms and conditions set forth in the JOA; and

WHEREAS, Canal is the sole owner of the site on which Canal Unit 2 is located and sole owner of an adjacent electric generating facility known as "Canal Unit 1" ("Canal Unit 1") and adjoining and related parcels of undeveloped real property (collectively, the "Canal Site"), and is the operator of both Canal Unit 1 and Canal Unit 2; and

WHEREAS, Canal is interested in selling the Canal Site, Canal Unit 1 and its interest in Canal Unit 2 and is in the process of conducting an auction of such assets with the assistance of Goldman, Sachs & Co. as financial advisor to Canal (the "Auction"); and

WHEREAS, Montaup is interested in selling its interest in Canal Unit 2, and desires to have its interest in Canal Unit 2 included in the Auction; and

WHEREAS, Canal is willing to include Montaup's interest in Canal Unit 2 in the Auction.

NOW, THEREFORE, in consideration of the foregoing, the mutual covenants contained herein and other good and valuable consideration, the parties hereby agree as follows:

1. Canal and Montaup each have provided to the other party copies of each party's confidential information memorandum covering Canal Unit 2, and will, promptly following the date hereof, provide to the other party all preliminary and final bids submitted to each such party to date by prospective third party purchasers with respect to the proposed purchase of each such party's interest in Canal Unit 2.

2. Canal shall include in the Auction Montaup's interest in Canal Unit 2, by soliciting from participants in the Auction bids which cover all of Canal's interest in the Canal Site, Canal Unit 1 and Canal Unit 2, and Montaup's interest in Canal Unit 2. Promptly following the date hereof, Montaup will prepare and provide to Canal for its review and approval a supplement to Canal's confidential information memorandum describing the Montaup interest in Canal Unit 2 being made available for sale in the Auction.

3. Montaup agrees that the Auction will be conducted pursuant to the process that has been designed by Canal and that Canal will continue to manage the conduct of the Auction. Canal will keep Montaup apprised of developments in the Auction

process. Employees of Montaup and EUA Service Corporation will participate in meetings with potential bidders and in meetings regarding the Auction process.

4. If a sale of Montaup's interest in Canal Unit 2 is consummated as a result of the Auction, Montaup shall be entitled to receive as consideration for its interest in Canal Unit 2 that percentage of the net consideration received by Canal and Montaup with respect to the sale of the Canal Site, Canal Unit 1 (solely for purposes of this calculation) and the interests of both Canal and Montaup in Canal Unit 2, determined as follows:

Net Consideration (000,000)		Percentage of Incremental Amount
$	0-200	20%
	200-250	16%
	250-300	18%
	300-350	14%
	350-400	12%
	> 400	10%

For purposes hereof, the net consideration shall be equal to 98.5% of the total purchase price paid by the purchaser of such assets.

5. Canal shall not under any circumstances be deemed to represent, warrant or guarantee that the Auction will be successful or that it will result in a fair price for the assets to be sold pursuant thereto, including Montaup's interest in Canal Unit 2.

6. Neither Canal nor Montaup shall be obligated to sell any assets pursuant to the Auction if the price to be paid is not acceptable to either of them in their respective sole discretions. The parties agree to develop terms and conditions for sale which are substantially consistent with, and in the form of, the draft Asset Sale Agreement developed by Canal included in the Confidential Offering Memorandum dated October 1997 of Canal. In this regard, Montaup shall agree to bear a proportionate share of any post-closing indemnification obligations and purchase price adjustments to which Canal agrees with the purchaser of the Canal assets (other than post-closing indemnification obligations of Canal with respect to environmental and other matters for which the owners of Canal Unit 2 would not be responsible under the existing contractual arrangements respecting Canal Unit 2) as is equal to Montaup's proportionate share of the total purchase price for the Canal assets paid by such purchaser. The parties shall jointly consider on a case-by-case basis expenditures and commitments which are designed to optimize the terms and conditions of the sale of the Canal assets. Each party will indemnify the other against the effect of any deviations in terms and conditions which are solely applicable to such party's interest in Canal Unit 2 or its other assets or obligations associated with Canal Unit 2.

7. Canal agrees to provide to Montaup periodic progress reports with respect to the Auction.

8. Montaup agrees that neither it nor its affiliates, agents or representatives, will, so long as this Memorandum of Understanding remains in effect, seek to sell, offer to sell or sell all or any part of its interest in Canal Unit 2 other than pursuant to the Auction and in accordance with the terms hereof, nor will they or any of them contact any of the participants in the Auction or make any public announcements (other than as required by law) with respect to the Auction without Canal's prior written consent, which it may grant or withhold in its discretion.

9. Each of Canal and Montaup hereby waives the right of first refusal rights that each of them currently has under the JOA with respect to any sale of their interests in Canal Unit 2 pursuant to the Auction. Each of Canal and Montaup hereby agrees not to make any material commitments with respect to their interests in Canal Unit 2 other than as contemplated or permitted by the JOA.

10. Montaup hereby agrees that it will notify all governmental parties with which it entered into a settlement agreement on electric restructuring issues in both Massachusetts and Rhode Island of the joint marketing effort with respect to Canal Unit 2. Each of Montaup and Canal agrees to keep the other informed of all developments and communications relating to the sale of Canal Unit 2 with such governmental parties, and each of Canal and Montaup further agrees not to make any commitments with such governmental parties with respect to Canal Unit 2 without the prior written consent of the other and to use reasonable efforts to include the other in all meetings with such governmental parties which relate to Canal Unit 2.

11. The obligations of the parties under this Memorandum of Understanding (other than under Sections 1, 3 and 9 hereof) are subject to the approval hereof by the Boards of Directors of each of Canal and Montaup within three days of the date of this Memorandum of Understanding.

12. This Memorandum of Understanding shall terminate and be of no further force or effect if definitive agreements for the sale of Canal's and Montaup's interests in Canal Unit 2 have not been executed and delivered by each of Canal and Montaup on or before August 31, 1998, unless such date is extended by mutual agreement of the parties.

13. Each of Canal and Montaup shall bear their own expenses in connection with this Memorandum of Understanding and the Auction, and neither party shall be liable or responsible for the costs and expenses of the other.

14. The parties acknowledge their respective obligations under certain Confidentiality Agreements executed by the parties and dated as of January 28, 1998, and hereby agree that the provisions thereof shall continue in full force and effect notwithstanding the execution and delivery of this Memorandum of Understanding. Nothing in this Memorandum of Understanding shall be deemed to affect the respective rights and obligations of Montaup and Canal under the JOA or under the Power Contract dated December 1, 1965 relating to Canal Unit 1, except as otherwise expressly provided herein.

15. This Memorandum of Understanding may be executed in one or more counterparts, which together shall constitute one and the same instrument. This Memorandum of Understanding shall be governed by and construed in accordance with the laws of the Commonwealth of Massachusetts, without giving effect to the conflicts of laws provisions in effect therein.

IN WITNESS WHEREOF, the parties have executed this Memorandum of Understanding as of the date first set forth above.

CANAL ELECTRIC COMPANY

By: James J. Keane
Name: James J. Keane
Title: Vice President,
Energy Supply & Engineering Services

MONTAUP ELECTRIC COMPANY

By: Kevin A. Kirby
Name: Kevin A. Kirby
Title: Vice President, Power Supply

EXHIBIT JJR-1

Prepared Direct Testimony of

John J. Reed

EXHIBIT JJR-1

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Eastern Edison Company Montaup Electric Company	)	D.T.E. 98-83

PREPARED DIRECT TESTIMONY OF

JOHN J. REED

I. INTRODUCTION

Q. Please state your name, affiliation, and business address.

A. My name is John J. Reed. I am President of Reed Consulting Group (REED), 200 Wheeler Road, Burlington, Massachusetts 01803.

Q. Please describe the nature of the services provided by REED.

A. REED is a management, economic and financial consulting firm that provides services to utilities, energy producers, major energy consumers, project developers and governmental authorities throughout the United States and Canada. REED provides a wide array of consulting services, including economic and financial analysis, rate and regulatory analysis, litigation support and expert testimony, energy supply and market analysis, merger and acquisition services, strategic and business planning services, restructuring and reengineering services, energy policy analysis and project development services.

Q. Please describe your professional experience.

A. I have served as an executive and manager with other consulting firms and as Corporate Economist for Southern California Gas Company. I have provided expert testimony on rate and regulatory matters in more than one hundred cases before the Federal Energy Regulatory Commission (the "Commission"), the National Energy Board of Canada, more than fifteen state utility regulatory agencies, and various state courts in civil proceedings. A summary of my professional experience and educational background is presented as Appendix A to my testimony.

Q. What is the nature of REED's assignment for Montaup?

A. REED was retained by Montaup Electric Company ("Montaup" or the "Company") in January 1998 to design and manage the marketing for the divestiture of its generation business. REED's role throughout this process has been to manage each aspect of the divestiture, including defining the terms of sale, identifying and organizing all necessary information and disseminating it to the interested parties, developing and implementing the marketing effort for the assets, and managing the bidding process beginning with indicative bids through contract negotiation and closing.

Q. What resources are being marketed?

A. The majority of Montaup's generating resources, and those of its affiliates, are being considered for sale. These include the ownership interest in Canal 2, the Somerset Station, the Pawtucket Hydroelectric Station (owned by Montaup's affiliate, Blackstone Valley Electric Company), the ownership interest in Wyman #4 unit, several real estate parcels, and the Company's purchase power agreements.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe Montaup's ownership interest in Canal Unit 2, to review the considerations that went into Montaup's decision to jointly market the unit, and to assess the reasonableness of the sale price received by Montaup for its ownership interest in Canal Unit 2.

II. MONTAUP'S SALE OF CANAL UNIT 2

Q. What are Montaup's ownership interests in the Canal Generating Station?

A. Montaup is the co-owner, along with Commonwealth Energy System's affiliate, Canal Electric Company ("Canal"), of Canal Unit 2. Canal and Montaup hold as tenants in common undivided 50% shares in the unit. Canal also owns and operates Canal Unit 1, which along with Canal Unit 2, related facilities and associated land parcels is known as the "Canal Generating Station." As part of its ownership interest in Canal Unit 2, Montaup has the associated leasehold and personal property rights as well as the right to use, in common with Canal, Canal Unit 1 facilities necessary for the operation of Canal Unit 2. However, Montaup does not have any rights or ownership interests in the Canal site that would allow it to develop or participate in the development of additional generation at the Canal site. These factors make less valuable Montaup's interest relative to Canal's. In addition, Canal is the designated, sole operator of the unit. Development potential of the site and operating control are deemed critical by most prospective buyers of generation assets and, therefore, enable the holder of these rights to command a premium relative to those who do not have ownership of these rights.

Q. Please briefly describe the proposed terms of Montaup's sale of Canal Unit 2.

A. Montaup is proposing to sell its 50% ownership share in Canal Unit 2 (280 MW) for $75.1 million to Southern Energy New England, L.L.C. This sale is the result of Montaup's participation, under a joint marketing agreement negotiated between Montaup and Canal, in the auction process in which Canal and its affiliates offered all of their non-nuclear generating facilities for sale.

Q. How do Canal Unit 1 and Unit 2 compare?

A. They are distinctly different. Canal Unit 1 is a 560-MW baseload, supercritical oil-fired unit and is among the most efficient and hence lowest variable operating cost oil units in the Northeast. Canal is the owner and operator of Unit 1, the output of which is completely committed under unit sale agreements with Montaup (25%), Boston Edison Company (25%), New England Power Company ("NEP") (25%), and Canal's affiliates, Commonwealth Electric Company and Cambridge Electric Light Company, which jointly purchase 25% of the unit's output. NEP's rights under its Canal Unit 1 agreement will be transferred to USGen New England, Inc. ("USGenNE") with the consummation of NEP's sale to USGenNE of its ownership interests in its fossil and hydro units as well as the transfer of its power purchase agreements. Canal Unit 2 is a 564-MW intermediate unit that is capable of burning both oil and natural gas.

III. THE DECISION TO PARTICIPATE IN JOINT MARKETING

Q. What role did REED play in support of Montaup's decision to market its interest in Canal Unit 2 jointly with Canal?

A. After we were engaged by Montaup to direct the marketing of its generating assets and power purchase agreements in January 1998, we recommended that Montaup continue discussions with Canal for the joint marketing of Canal Unit 2. REED believed that jointly marketing Montaup's interest in Canal Unit 2 was the best strategy for maximizing the proceeds from the sale of its interest in Canal Unit 2, assuming that Montaup could negotiate a reasonable agreement with Canal for the division of proceeds from the sale of the Canal Generating Station. We confirmed this assessment based on discussions with a number of prospective bidders who indicated that combining Montaup's Canal Unit 2 entitlement with Canal's would cause them to increase their overall value for the generating station and, as such, would likely result in higher per unit, i.e., $/kW, revenues from the sale for Montaup. Also, certain prospective bidders indicated that they would only be interested in bidding for Canal Unit 2 if they could bid on the entire unit.

Q. What were the alternatives to jointly marketing with Canal?

A. Montaup could have separately marketed its 50% ownership interests in Canal Unit 2 as part of its own divestiture process and not capture any of the potential synergies offered by joint marketing. However, there were a number of disadvantages with this strategy. First, based on our experience with other generation asset sales, it was clear that bidders would discount any ownership interests that did not provide operating control of the unit. In addition, bidders for Montaup's entitlement in Unit 2 would essentially have a minority ownership interest in the plant, i.e., approximately 25% of the entire station, and no rights to participate in the expansion or repowering of the site. Therefore, it became clear that the best strategy for maximizing the proceeds from the sale of Montaup's ownership interest in Canal Unit 2 would be to enable one bidder to purchase Canal's and Montaup's joint interests in Canal.

This suggested that parallel marketing might be a viable alternative, i.e., contemporaneously with Canal. However, any bidder for Montaup's interest in Canal Unit 2 in the Montaup divestiture process could not be sure that it would be the winning bidder in the Canal auction, and Montaup's Canal Unit 2 ownership interest was much less valuable if the bidder did not secure Canal's interest. Therefore, under a parallel marketing scheme there was no way in which Montaup could secure proceeds that did not reflect a significant discount relative to the proceeds that were likely from jointly marketing the assets.

Q. Was there an objective method that could be used by the two parties to determine the relative value of Montaup's and Canal's interest?

A. No. The values placed on the differences between the respective rights of the two parties are likely to vary from bidder to bidder and there is no objective method to determine a fair sharing of the proceeds from the sale. Since bidders were asked to submit a single price for the entire Canal Generating Station, it was necessary for the two parties to negotiate a fair sharing of these proceeds. Naturally, at the time of the negotiation, neither party could know the ultimate sale price. Based in part on REED's recommendation, the formula for sharing proceeds from the sale was designed to provide Montaup with a higher percentage of proceeds at the lower end of the price schedule. The overall schedule provides a reasonable allocation of proceeds throughout the range on sale prices.

Q. Do you believe that the allocation that Montaup agreed to was reasonable?

A. Yes. While REED did not participate in the negotiations, we advised Montaup in the negotiations. In my opinion, the deal negotiated was reasonable.

IV. <u>THE REASONABLENESS OF MONTAUP'S PROCEEDS</u>

Q. Did Montaup maximized the price of its interest in Canal Unit 2 in the sale to Southern?

A. Absolutely. While it is very difficult to compare the results of generation sales that have occurred on different terms and for ownership interests where the buyer may have had greater rights than to be conveyed by Montaup, it is possible to make a general comparison based on summary statistics. As shown on Exhibit JJR-2, Montaup's sales price is comparable with other generation asset sales, particularly given that Montaup's ownership interest in Canal Unit 2 did not provide Southern with any rights to develop the Canal Generating Station site or provide it with operating control.

Q. Does this conclude your prepared direct testimony?

A. Yes.

EXHIBIT JJR-2

Divestiture Proceeds Matrix

Exhibit JJR-2

Company	MW Sold	Sale Price	Book Value	$/kW	Price/Book
NEES	5,117	$1.59 b	$1.1 b	$311	1.45
SoCalEd	9,562	$1.19 b	$621 m	$124	1.92
PG&E	2,645	$501 m	$380 m	$189	1.32
BECo	1,987	$657 m	$450 m	$331	1.46
CMP	1,185	$846 m	$240 m	$713	3.53
ComEnergy	984	$462 m	$79 m	$470	5.85
Montaup Canal 2	280	$75 m	$39 m	$268	1.92

EXHIBIT DTS-1

Prepared Direct Testimony of

Don T. Sena

EXHIBIT DTS-1

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Eastern Edison Company	)	
Montaup Electric Company	)	D.T.E. 98-83

PREPARED DIRECT TESTIMONY OF
DONALD T. SENA

I. QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Donald T. Sena, and my business address is One Liberty Square, Boston, Massachusetts 02109.

Q. What is your present position?

A. I am the Assistant Treasurer of EUA Service Corporation ("EUASC") and all Eastern Utilities Associates ("EUA") subsidiary companies, including Montaup Electric Company (the "Company" or "Montaup"), Blackstone Valley Electric Company ("Blackstone"), Newport Electric Corporation ("Newport"), and Eastern Edison Company ("Eastern") (Montaup, Blackstone, Newport and Eastern, together "the EUA Companies").

Q. Please describe your responsibilities as Assistant Treasurer.

A. I have the responsibility for assisting the Treasurer of EUA in all Treasury functions within the EUA System, including the following: planning and execution of long-term financing for System companies; banking relations; cash management functions; EUA investor relations; financial forecasting; and external financial reporting.

Q. Please summarize your educational background and training.

A. I was graduated from Southeastern Massachusetts University ("SMU," now the University of Massachusetts at Dartmouth) in 1973 with a Bachelor of Science degree in Accounting. In 1977 I received a Masters of Business Administration degree from SMU. I have also attended several utility professional development programs, including the Electric Council of New England ("ECNE") Skills of Utility Management Program and the Irving Trust (now Bank of New York) Public Utilities Financial Seminar.

Q. What is your professional background?

A. I joined the EUA System in 1978 and was employed by EUASC as an Internal Auditor. In 1980, I transferred to the EUASC Rate Department as a Rate Analyst. A year later, I transferred to the newly formed EUASC Revenue Requirements Department. During the period of 1981 through mid-1984, I held the positions of Revenue Analyst and Senior Revenue Analyst while working in the Revenue Requirements Department. In mid-1984, I was promoted to the position of Supervisor of Financial Services in EUASC's Treasury Department, located in Boston. My responsibilities in this position included financial reporting and financial forecasting for all EUA System Companies. In 1988, I was promoted to Manager of Treasury Services which extended my responsibilities to also include overall budget administration for all EUA System Companies. In 1990, I was promoted to Manager of EUASC's Rate Department, located in West Bridgewater. My responsibilities encompassed the preparation and coordination of all rate filings for the retail and wholesale electric companies within the EUA System. In July 1993, I was promoted to Assistant Treasurer. My current responsibilities are as stated above. I have previously sponsored testimony before the Rhode Island Public Utilities Commission ("RIPUC") and the Federal Energy Regulatory Commission ("FERC").

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support Montaup's proposed sale of its 50% ownership interest in Unit No. 2 of the Canal Generating Station ("Canal 2") to Southern

Energy New England, L.L.C. ("Southern"), by demonstrating the benefits to Eastern's retail customers of the transaction.

Q. How is your testimony organized?

A. The remainder of my testimony is presented in three sections. First, I present a summary of the benefits to Eastern that are produced by the divestiture of Canal 2, in the form of reductions to the Contract Termination Charges ("CTC") that Montaup is entitled to collect from Eastern. Second, I describe the terms under which Eastern will reflect its reduced CTC obligations in rates charged to its retail customers. Finally, I discuss the disposition of Montaup's ownership interest in transmission facilities at the Canal Generating Station.

III. CUSTOMER BENEFITS OF DIVESTITURE

Q. Please describe the estimated benefits to Montaup's customers as a result of the proposed sale of Canal 2.

A. As a result of the sale of Canal 2 to Southern and the sale of switchyard transmission facilities to Commonwealth Electric Company ("Commonwealth"), Montaup will receive $75.7 million in gross proceeds, and will terminate its existing entitlement exchange agreements with Taunton Municipal Lighting Plant ("Taunton") and Braintree Electric Light Department ("Braintree"), thereby eliminating all future costs and revenues associated with those arrangements. The net result of these transactions will be to reduce the total CTC obligation of Eastern, Blackstone, and Newport. These reduced costs will in turn reduce the transition charges paid by the retail electric customers of Eastern, Blackstone, and Newport.

Q. How is Montaup's CTC structured?

A. The CTC, which is defined in the Stipulation and Agreement between Eastern, Montaup, the Attorney General and the Division of Energy Resources approved by FERC in Docket Nos. ER97-2800-000 *et al* (the "FERC Settlement"), comprises a fixed component, which provides for the recovery of generation investments and regulatory assets, and a variable component, which provides for the recovery of above-market purchase power costs, nuclear decommissioning and related costs, and several other categories of costs which can be estimated but which will not be known until they are incurred.

Q. Under the settlement agreements, how are the benefits of Montaup's divestiture transactions flowed back to its affiliated customers?

A. Net proceeds from the sale of generation assets, such as in the Canal 2 sale, will reduce the fixed component of the CTC through the Residual Value Credit ("RVC") mechanism. The FERC Settlement defines the timing of implementing the RVC, and the methodology to flow the credit to customers.

Q. How are the benefits from the termination of Montaup's exchange agreements with Taunton and Braintree reflected in the CTC?

A. The exchange agreements are described by Mr. Hirsh in his testimony (Exhibit MJH-1). The above-market costs associated with Montaup's purchases from Taunton and Braintree are included in the variable component of the CTC, as are the revenues Montaup would receive associated with sales of Canal 2 under the exchange agreements. Terminating these exchange agreements eliminates both the above-market costs and the associated revenues that would otherwise be included in the collection of the variable component of the CTC. The net effect is a reduction in the variable component of the CTC. During the first three years of the CTC, the variable component is set at a fixed level. Differences between the set amount and the actual costs incurred are accumulated in a Reconciliation Account. The accumulated Reconciliation Account will flow back to Montaup's wholesale customers beginning in 2001. The account reconciles annually thereafter. The benefit of the purchase power contract terminations will be reflected as a credit to the Reconciliation Account.

Q. Have you performed any estimates of the residual value credit resulting from Montaup's sale of Canal 2?

A. Yes. My prepared direct testimony and exhibits submitted to FERC in support of the joint application for approval of the Canal 2 sale (Exhibit DTS-2) presents an estimate of an "Initial RVC" that reflects only the proceeds from the Canal 2 sale. As is discussed in detail in my FERC testimony, Montaup intends to file for approval and implement a single residual value credit which reflects the divestiture proceeds from substantially all of Montaup's non-nuclear assets. However, since Montaup does not yet have definitive agreements for the sale of all of its non-nuclear assets, the total residual value credit cannot be estimated at this time.

IV. SETTLEMENT PROVISIONS FOR ACCESS CHARGES

Q. How will Eastern reflect its reduced CTC obligations to Montaup in lower retail rates for its customers?

A. Under the Restructuring Settlement Agreement approved by the Department in D.P.U./D.T.E. 96-24 (the "RSA"), Eastern is entitled to recover from its customers "[a]ccess charges that are designed to recover on a fully reconciling basis all contract termination charges paid by Eastern to Montaup." RSA Section I.B.1(c), Exhibit DTS-3 at 8. Among other adjustments, Eastern's access charges are "subject to a residual value credit under" the FERC Settlement. *Id.* Eastern will reduce its access charge rate concurrently with the reduced CTC charges from Montaup.

Q. Will all customers receive the same credit to their access charges?

A. Yes. Under the terms of Eastern 's *Transition Charge Adjustment Clause,* M.D.T.E. No. 363 (Exhibit DTS-4):

> The initial termination charge [CTC] shall be incorporated within the Transition Charges [access charges] established for each rate class and distributed among the several components thereof at a level equivalent to $0.03040/kWh through December 31, 2000, subject to adjustment for the Residual Value Credit allowed by the Federal Energy Regulatory Commission upon the divestiture of Montaup's non-nuclear generating facilities as they occur. Thereafter, the Transition Charges for each rate class shall be adjusted by applying an Adjustment Multiplier each time that the termination charge Montaup bills to the Company changes. The Adjustment Multiplier to be applied to the Transition Charges for each rate class shall be determined by:
>
> 1. Calculating the expected revenues from the application of the new termination charge for the period during which the Adjustment Multiplier will be in effect;
>
> 2. Calculating the actual revenue difference between the termination charges paid and the Transition Charge revenues received during the period beginning with the effective date of the initial termination charge and ending with the effective date of the new termination charge;
>
> 3. Dividing the sum of the foregoing revenues by the initial termination charge revenues calculated for the period during which the Adjustment Multiplier will be in effect.

V. TRANSMISSION ISSUES

Q. Please describe the transaction involving Montaup's ownership interest in transmission facilities at the Canal Generating Site.

A. Southern will be buying, from Canal and Montaup, those station and switchyard facilities classified to the generation function and needed to interconnect the Canal units to NEPOOL Pool Transmission Facilities ("PTF") at the Canal Site. Commonwealth, an affiliate of Canal, will purchase Montaup's and Canal's ownership interests in PTF at the Canal Site, and will continue to operate and maintain the Canal Site PTF, along with its other PTF and non-PTF, pursuant to FERC-approved open access transmission tariffs for itself and for NEPOOL. Under the terms of the Bill of Sale and Agreement between Montaup and Commonwealth (Exhibit MJH-7), Commonwealth will pay Montaup the net book value of the facilities shown on Montaup's books as of the closing date of the sale to Southern, approximately \$600,000. Thereafter, Montaup will have no further interest in transmission facilities at the Canal Site.

Q. How will the CTC be adjusted to reflect the sale of these transmission assets?

A. Since the transmission assets are in Montaup's CTC, the proceeds from the sale are included in the Initial RVC estimate, and will be included in the calculation of the RVC which will be filed later for FERC approval.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT DTS-2

Prepared Direct Testimony

And Exhibits Of

Donald T. Sena

Exhibit MEC-5
(DTS-1)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Cambridge Electric Company,	)	
Canal Electric Company,	)	
Commonwealth Electric Company,	)	Docket No. EC98-_____
Montaup Electric Company,	)	
Southern Energy New England, L.L.C.,	)	
Southern Energy Canal, L.L.C, and	)	
Southern Energy Kendall, L.L.C.	)	

PREPARED DIRECT TESTIMONY OF
DONALD T. SENA
ON BEHALF OF MONTAUP ELECTRIC COMPANY

I. QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Donald T. Sena, and my business address is One Liberty Square, Boston, Massachusetts 02109.

Q. What is your present position?

A. I am the Assistant Treasurer of EUA Service Corporation ("EUASC") and all Eastern Utilities Associates ("EUA") subsidiary companies, including Montaup Electric Company (the "Company" or "Montaup"), Blackstone Valley Electric Company ("Blackstone"), Newport Electric Corporation ("Newport"), and Eastern Edison Company ("Eastern") (Montaup, Blackstone, Newport and Eastern, together "the EUA Companies").

Q. Please describe your responsibilities as Assistant Treasurer.

A. I have the responsibility for assisting the Treasurer of EUA in all Treasury functions within the EUA System, including the following: planning and execution of long-term financing for System companies; banking relations; cash management functions; EUA investor relations; financial forecasting; and external financial reporting.

Q. Please summarize your educational background and training.

A. I was graduated from Southeastern Massachusetts University ("SMU," now the University of Massachusetts at Dartmouth) in 1973 with a Bachelor of Science degree in Accounting. In 1977 I received a Masters of Business Administration degree from SMU. I have also attended several utility professional development programs, including the

Electric Council of New England ("ECNE") Skills of Utility Management Program and the Irving Trust (now Bank of New York) Public Utilities Financial Seminar.

Q. What is your professional background?

A. I joined the EUA System in 1978 and was employed by EUASC as an Internal Auditor. In 1980, I transferred to the EUASC Rate Department as a Rate Analyst. A year later, I transferred to the newly formed EUASC Revenue Requirements Department. During the period of 1981 through mid-1984, I held the positions of Revenue Analyst and Senior Revenue Analyst while working in the Revenue Requirements Department. In mid-1984, I was promoted to the position of Supervisor of Financial Services in EUASC's Treasury Department, located in Boston. My responsibilities in this position included financial reporting and financial forecasting for all EUA System Companies. In 1988, I was promoted to Manager of Treasury Services which extended my responsibilities to also include overall budget administration for all EUA System Companies. In 1990, I was promoted to Manager of EUASC's Rate Department, located in West Bridgewater. My responsibilities encompassed the preparation and coordination of all rate filings for the retail and wholesale electric companies within the EUA System. In July 1993, I was promoted to Assistant Treasurer. My current responsibilities are as stated above. I have previously sponsored testimony before the Rhode Island Public Utilities Commission ("RIPUC").

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support Montaup Electric Company's ("Montaup") proposed sale of its 50% ownership interest in Unit No. 2 of the Canal Generating Station ("Canal 2") to Southern Energy New England, L.L.C. ("Southern"), by demonstrating the benefits to Montaup's customers of the transaction.

Q. How is your testimony organized?

A. The remainder of my testimony is presented in five sections. First, I present a summary of the benefits to Montaup's customers that are produced by the divestiture of Canal 2, in the form of reductions to the Contract Termination Charges ("CTC") that Montaup is entitled to collect from its affiliated wholesale customers. Second, I describe the terms under which Montaup will collect the CTC, and the provisions for crediting Montaup's customers with the results of its stranded cost mitigation efforts through a Residual Value Credit ("RVC") to the CTC. Third, I discuss certain timing considerations involved in the implementation of Montaup's RVC. Fourth, I present a series of schedules and workpapers illustrating the calculation of the RVC. Finally, I discuss the disposition of Montaup's ownership interest in transmission facilities at the Canal Generating Station.

III. CUSTOMER BENEFITS OF DIVESTITURE

Q. Please describe the estimated benefits to Montaup's customers as a result of the proposed sale of Canal 2.

A. As a result of the sale of Canal 2 to Southern and the sale of switchyard transmission facilities to Commonwealth Electric Company ("Commonwealth"), Montaup will receive

$75.7 million in gross proceeds, and will terminate its existing entitlement exchange agreements with Taunton Municipal Lighting Plant ("Taunton") and Braintree Electric Light Department ("Braintree"), thereby eliminating all future costs and revenues associated with those arrangements. The net result of these transactions will be to reduce the total CTC obligation of Eastern, Blackstone, and Newport. These reduced costs will in turn reduce the transition charges paid by the retail electric customers of Eastern, Blackstone, and Newport.

Q. Will Montaup's unaffiliated wholesale power customers be affected by Montaup's divestiture transactions?

A. No. Montaup is providing wholesale power supply to Middleborough Gas & Electric Department ("Middleborough") and the Pascoag (RI) Fire District ("Pascoag") at fixed rates under separate agreements with those parties. Docket Nos. ER97-3127-000 and ER97-2800-000. The services and rates provided under these agreements are not affected by changes in Montaup's CTC.

Q. Will Montaup's transmission customers be affected by Montaup's divestiture or the sale of its switchyard facility interests at Canal?

A. No. Montaup's sale of its transmission facilities to Commonwealth will not affect Montaup's ability to offer open-access transmission service or its rates therefor under its Open Access Transmission Tariff. Docket No. OA96-67-000.

Q. Is Montaup requesting approval of its RVC associated with the sale of Canal 2 at this time?

A. No. As I explain more fully below, Montaup intends to file a separate application with the Commission for adjustment of its CTC rates, incorporating the results of several divestiture transactions. Ideally, Montaup will implement fully its RVC in a single adjustment to the CTC within three months of the closing of the Canal 2 sale.

IV. SETTLEMENT PROVISIONS FOR CONTRACT TERMINATION CHARGES

Q. What agreements govern Montaup's calculation and collection of its stranded costs?

A. During 1996 and 1997, the EUA Companies entered into settlement agreements with parties in Massachusetts and Rhode Island in order to effect a comprehensive resolution of the complex, interrelated issues associated with restructuring the electric utility industry. As part of those agreements, the EUA Companies committed to a complete divestiture of their generating business and Montaup was allowed to collect all of its stranded generation-related costs through a Contract Termination Charge ("CTC") from its former all-requirements customers, Eastern, Blackstone, and Newport. The calculation and collection of the CTC are governed by these wholesale settlement agreements as approved by the Commission in Docket Nos. ER97-3127-000, ER97-2800-000, and ER97-2338-000 on December 19, 1997, and as amended by Montaup's January 20, 1998 compliance filing. Agreements with parties in Massachusetts and Rhode Island and approved by state regulatory authorities govern the retail aspects of restructuring.

Q. How is the CTC structured?

A. The CTC comprises a fixed component, which provides for the recovery of generation investments and regulatory assets, and a variable component, which provides for the recovery of actual above-market purchase power costs, nuclear decommissioning and related costs, and several other categories of costs which can be estimated but which will not be known until they are incurred.

Q. Under the settlement agreements, how are the benefits of Montaup's divestiture transactions flowed back to its affiliated customers?

A. Net proceeds from the sale of generation assets, such as in the Canal 2 sale, will reduce the fixed component of the CTC through the Residual Value Credit ("RVC") mechanism. The settlement agreements define the timing of implementing the RVC , and the methodology to flow the credit to customers. Exhibit MEC-6-8(DTS-2), Section 1.1.4(c).

Q. How are the benefits from the termination of Montaup's exchange agreements with Taunton and Braintree reflected in the CTC?

A. The exchange agreements are described by Mr. Hirsh in his testimony (Exhibit MEC-1). The above-market costs associated with Montaup's purchases from Taunton and Braintreee are included in the variable component of the CTC, as are the revenues Montaup would receive associated with sales of Canal 2 under the exchange agreements. Terminating these exchange agreements eliminates both the above-market costs and the associated revenues that would otherwise be included in the collection of the variable component of the CTC. The net effect is a reduction in the variable component of the CTC. Under the approved settlement agreements with Blackstone and Newport, Montaup is entitled to retain a portion of the CTC savings as a "Power Contract Buyout Incentive Associated with Canal 2 Divestiture." (Exhibits MEC-6-BVE (DTS-2-BVE) and MEC-7-NEC (DTS-2-NEC) at 17, Section 1.2.2(b)(iv)). During the first three years of the CTC, the variable component is set at a fixed level. Differences between the set amount and the actual costs incurred are accumulated in a Reconciliation Account. The accumulated Reconciliation Account will flow back to customers beginning in 2001. The account reconciles annually thereafter. The benefit of the purchase power contract terminations will be reflected as a credit to the Reconciliation Account.

V. IMPLEMENTING THE RESIDUAL VALUE CREDIT

Q. Under the settlement agreements, when is the Residual Value Credit to be implemented?

A. Section 1.1.4(c) of Exhibit MEC-6 (DTS-2) states that the RVC will be implemented "within three months after completion of divestiture or the sale of any property," and "[t]he Residual Value Credit will be deemed to be fully implemented upon completion of the initial divestiture process for Montaup's non-nuclear generating facilities." The purpose of these provisions is to ensure that the mitigation benefits of divestiture are flowed back to customers promptly upon Montaup's receipt of any substantial divestiture proceeds.

Q. When will the "completion of the initial divestiture process" occur for the EUA Companies?

A. Completion of the initial divestiture process, for purposes of implementing Montaup's RVC, will occur upon the closing of the sales of both its Canal 2 interest and the

Somerset Station ("Somerset"). These units account for essentially all of Montaup's non-nuclear generating assets, and virtually all of Montaup's RVC is expected to result from the sales of these two assets. Once these two assets are sold, the RVC will be fully implemented and there will be no further adjustments to the fixed component of the CTC. Any future sales of assets or property will be reflected in the variable component of the CTC, pursuant to the Settlement.

Q. Why is it necessary to establish a completion date for the RVC?

A. Once Montaup's Canal 2 and Somerset entitlements are sold, Montaup's ability to mitigate the CTC by divesting its owned generating resources is, essentially, ended. By declaring the RVC "fully implemented," the stream of payments from the fixed component of the CTC becomes truly fixed. At that point, Montaup can seek additional savings through securitization or other financing mechanisms.

Q. Will the EUA Companies sell all of their generation-related properties in a single transaction?

A. No, there will be multiple transactions. Newport has previously executed an agreement to sell its diesel generating units, with closing expected to occur in the fourth quarter of 1998. The proposed Canal 2 sale may, under the terms of the Asset Sale Agreement (Exhibit H), close as early as November 1998. The remainder of Montaup's generation-related assets are currently being offered in a market auction process, with agreements anticipated in late summer. As a result, the sales of the various assets, to different parties, will close in separate transactions.

Q. Since Montaup's assets are not all being sold to a single buyer in one transaction, how does Montaup intend to implement the RVC?

A. Pursuant to the requirement in the settlement agreements that the RVC be implemented "within three months of . . . the sale of any property," Montaup will file a rate application with the Commission for approval to implement an RVC, with the new CTC rates proposed to become effective within three months of the closing of the Canal 2 sale. Assuming that the Somerset sale will close within three months of the Canal 2 sale, Montaup intends to file a single RVC that will include substantially all of Montaup's non-nuclear divestiture transactions. The RVC will therefore be "fully implemented" in a single filing and rate adjustment. The RVC will include all of the divestiture proceeds received, reduced by transaction costs, lost revenues and other offsetting costs or accruals associated with the filed transactions, pursuant to the terms of the settlements. Depending on the timing of the two sale closings, this may require a waiver request to make the RVC rates effective on less than sixty days' notice.

Q. How will the RVC be implemented if the Somerset sale does not close within three months of Canal 2?

A. Under the terms of the settlement agreements, Montaup must file to implement a RVC within three months of completing the Canal 2 sale in any event. If the Somerset sale is not going to be completed within three months of the Canal 2 sale, Montaup will seek Commission approval to implement its RVC in two stages, with two separate rate filings.

Q. Please describe the first RVC rate filing under this scenario.

A. As soon after the closing of the Canal 2 sale as Montaup determines that the Somerset sale will not close within three months, Montaup will file for Commission approval of a CTC rate adjustment reflecting those net divestiture proceeds received up to and including the Canal 2 sale (the "Initial RVC").

Q. Please describe how Montaup would complete the implementation of its RVC.

A. Within three months after the closing of the Somerset sale, Montaup would file a supplemental rate application to complete the RVC implementation, capturing the remaining proceeds and remaining costs associated with the divestiture. These rates would be proposed to become effective within three months of the closing of the sale of Somerset. The RVC would be fully implemented at that point, and the proceeds from any future sales would be flowed through the Reconciliation Account.

Q. In either scenario, would all of the offsets to sales proceeds (transaction costs, etc.) be fully known at the time of the RVC implementation?

A. No, they would not. Montaup will propose in its RVC application(s) a mechanism and schedule for truing-up and reconciling the RVC within a known period after implementation.

VI. "INITIAL RESIDUAL VALUE CREDIT" ESTIMATE

Q. How will the proposed Canal 2 sale affect the components of Montaup's CTC?

A. The proposed Canal 2 sale will affect both the fixed and variable components of the CTC. The fixed component will be reduced as a result of net sales proceeds and the resulting RVC calculation. The variable component will be reduced as a result of the termination of Montaup's exchange agreements with Taunton and Braintree, as I described earlier.

Q. Have you performed any estimates of the expected RVC?

A. Since Montaup does not yet have sales agreements for all of its non-nuclear assets, we have not performed an estimate of the RVC for the entire divestiture. I have calculated, for this filing, an estimate of the RVC that would result strictly from the proceeds of the Canal 2 sale. This serves as an estimate of the "Initial RVC" that Montaup would file associated with Canal 2 if it was unable to include both Canal and Somerset in the same RVC filing.

Q. What are your assumptions underlying your estimate of the Initial RVC?

A. The following assumptions are used for the Initial RVC estimate:

(1) Sale of Canal 2 takes place on 12/31/98.

(2) Sales proceeds reflect the sale of Canal 2 to Southern and the sale of Canal Site transmission facilities to Commonwealth.

(3) Offsets to total sales proceeds (Exhibit MEC-_, Section 1.1.4(c)) are estimated as of 12/31/98. One-time adjustments for FAS 87, FAS 106 and FAS 109 are not included in this estimate.

(4) All estimates are rounded to the nearest $100,000.

Q. How is the Residual Value Credit calculated?

A. As detailed in the formula for calculating the CTC (Exhibit MEC-6 3 (DTS-2), Section 1.1.4(c), the RVC will include the total proceeds from asset sales less i) potential Employee Severance and Retraining costs, ii) revenues lost or gained as a result of retail access, iii) post-1995 capital additions, and iv) transaction costs, including the costs of refinancings made necessary by divestiture. In addition, the RVC applied to Blackstone and Newport will be further reduced to recapture a differential in the return on equity applied to CTC balances, as stipulated in Section 1.1.2, footnote 4, of Exhibit MEC-6-BVE (DTS-2_BVE) and MEC-7-NEC (DTS-2-NEC), and pursuant to the URA.

Q. Have you provided exhibits that calculate the impact of your assumptions for Blackstone, Newport, and Eastern?

A. Yes I have. The exhibits for the calculation of the Initial RVC and the adjusted CTC have been arranged numerically and grouped by subsets: "BVE", "NEC" and "EEC" for Blackstone-, Newport-, and Eastern Edison-specific information, respectively. Therefore, each exhibit number, e.g., MEC-6-BVE (DTS-2-BVE), MEC-7-NEC (DTS-2-NEC), MEC-8-EEC (DTS-2-EEC), will contain the same substantive information, but the subset will designate that the amounts are for the specific company as identified above.

Q. How have you presented the estimated adjustments to the base CTC resulting from the proposed sale of Canal 2?

A. Where estimates can be made, I have done so. In other cases, there is no basis for a reasonable estimate, so I have provided a placeholder for illustration purposes. Exhibit MEC-10 (DTS-3), for all three Companies, is their respective Schedule 1 (CTC calculation) as filed in the wholesale settlement agreements and approved by the Commission on December 19, 1997. These schedules establish the "Base CTC" and are the platform from which all adjustments have been made.

Q. Please describe your calculation of the Initial RVC as a result of the Canal 2 sales agreement with your stated assumptions.

A. I would refer you to the calculation of the Initial RVC, Exhibit MEC-12-14 (DTS-4). This exhibit follows the presentation of items calculating the RVC as outlined in Exhibit MEC-6-8 (DTS-2), Section 1.1.4(c)(i) through (iv). The estimates used in this calculation are explained below.

Q. What are Montaup's expected total proceeds from the proposed sale of Canal 2?

A. Total proceeds from the proposed Canal 2 sale are estimated at $75.7 million, as shown on Workpaper page 1 (Exhibit MEC-21 (DTS-7)). To the stated proceeds of $75.1 from Southern, I have added another $0.6 million associated with the sale of Canal 2 transmission plant to Commonwealth, as shown in the Bill of Sale and Agreement, Exhibit MEC-_.

Q. Will a reserve be established to cover employee severance costs, as provided in the settlement agreements?

A. Yes. The Employee Severance cost estimate included in Exhibit MEC-12-14 (DTS-4) is equal to the total allowance for these costs provided in Section 1.1.4(c)(i) of Exhibit MEC-6-8 (DTS-2). A reserve will be established in this amount to cover actual severance and related costs that Montaup incurs. Any amounts so reserved and not expended will be flowed to Montaup's customers through the Reconciliation Account.

Q. What is Montaup's estimate of its lost revenues?

A. The settlement agreements define the lost revenues in the Amendment, Section 1.1.4(c)(ii) of Exhibit MEC-6-8 (DTS-2). Based upon this definition, Montaup's estimate of its total lost revenues as of December 31, 1998 is $17.3 million, as shown in Workpaper page 5 (Exhibit MEC-21 (DTS-7)).

Q. When will the lost revenues be known?

A. The actual amount of lost revenues will not be known until the books are closed for the month in which the divestiture of Canal 2 or Somerset, whichever is later, is completed.

Q. Please describe Montaup's estimate of capital additions since 12/31/95.

A. The estimate for post-1995 additions included on Exhibit MEC-12-14 (DTS-4) reflects Canal 2 amounts only and was calculated by first reconciling actual December 31, 1997 generation-related plant balances to the estimated December 31, 1997 balances included in the Base CTC, Exhibits MEC-9-BVE (DTS-3-BVE) and MEC-10-NEC (DTS-3-NEC), page 4 of 15, and Exhibit MEC-11-EEC (DTS-3-EEC), page 5 of 16. This reconciliation provides the actual post-1995 net additions, including cost of removal, salvage, and retirements, through December 31, 1997. Construction work in progress at December 31, 1997 and estimated expenditures for 1998 were added and then an estimated depreciation amount for 1998 was calculated in order to arrive at an estimated post-1995 net additions amount through December 31, 1998. Workpaper pages 2 and 3 in Exhibit MEC-21 (DTS-7) support this estimate.

Q. Please describe the nature of Montaup's transaction costs.

A. These are legal and consultant fees and financing costs associated with restructuring the capitalization of Eastern and Montaup which is necessitated as a result of the sale of Montaup's generation assets. Workpaper page 6 in Exhibit MEC-21 (DTS-7) summarizes these estimates. As stated on this workpaper, I have used placeholders for consulting and legal fees of $2 million and $3 million respectively. The financing costs on this workpaper cross-reference to Workpaper page 8 and reflect premium costs associated with recapitalizing Montaup and Eastern. Workpaper page 7 reflects debt and preferred stock of Eastern's capitalization which support the Montaup investment in rate base as of 12/31/97. Workpaper page 8, as I stated above, reflects our current expectation of the reductions in the overall amount of capitalization as a result of reducing Montaup's plant/rate base, and Workpaper page 9 reflects our estimate of what Eastern's capitalization will look like after divestiture.

Q. What are the net proceeds available for the Initial RVC after accounting for these costs?

A. Montaup's net proceeds from the Canal 2 sale, and its Initial RVC, is estimated at $29.0 million, as shown on Exhibit MEC-4-EEC (DTS-4-EEC).

Q. How is Montaup's RVC allocated to Eastern, Blackstone, and Newport?

A. Pursuant to the Settlement Agreements, each of Montaup's affiliated customers is allocated a fixed percentage of the applicable RVC. Eastern's share is 59.02% of the net RVC as calculated above. Blackstone's and Newport's fixed shares are 29.13% and 11.85%, respectively, but the net RVC applicable to these companies is subject to a further reduction to recapture a differential in the return on equity included in the CTC calculations, pursuant to their settlements and pursuant to the URA.

Q. Please describe the estimated differential in return on equity that will be netted from the proceeds in calculating Montaup's RVC as it applies to Blackstone and Newport.

A. As indicated in Exhibit MEC-6-BVE (DTS-2-BVE) and MEC-7-NEC (DTS-2-NEC), Section 1.1.2, Footnote 4:

> "The difference between the 11.34 percent and 13.09 percent returns as applied to unamortized balances prior to the Divestiture date shall be recovered, if Divestiture occurs, through an offset to the Residual Value Credit..."

The 13.09% return for the Rhode Island Companies is derived by replacing the Base CTC ROE of 9.2% with a "divestiture incentive" ROE of 11.4%. The amount included on Exhibit MEC-12-BVE (DTS-4-BVE) and MEC-13-NEC (DTS-4-NEC) reflects the differential between 13.09% and 11.34% for 1998 and is supported by Workpaper pages 10 and 11 (Exhibit MEC-21 (DTS-7)).

Q. What is the resulting RVC that you have estimated for Blackstone and Newport?

A. After deducting the "RI Return Differential" of $4.8 million, Exhibit MEC-12-BVE (DTS-4-BVE) and MEC-13-NEC (DTS-4-NEC) indicate an estimated net Initial RVC of $24.2 million to be applied to these two companies. Blackstone would receive a 29.13% allocation of the net Initial RVC, and Newport would receive an 11.85% allocation, as fixed in their respective settlement agreements (Exhibit MEC-6-BVE (DTS-2-BVE) and MEC-7-NEC (DTS-2-NEC), Section 1.1).

Q. Are there any other adjustments in calculating the RVC?

A. Yes. As shown on Exhibit MEC-12-14 (DTS-4), I have also made an adjustment for "Prepaid Taxes." This adjustment relates to the current tax liability on the book gain of the proposed Canal 2 sale which has not been previously supported by ratepayers. The current tax liability used in this adjustment is calculated at the bottom of Exhibit MEC-12-14 (DTS-4). Workpaper page 12 (Exhibit MEC-21 (DTS-7)) identifies the Canal tax basis in the calculation as $19.6 million. The impact of this adjustment is not directly on the net proceeds available for the RVC. Instead, this adjustment, along with an adjustment for Accumulated Deferred Taxes, reduces the effective RVC basis for purposes of calculating the approved return on unamortized RVC that is credited to customers.

Q. Does the calculation shown on MEC-12-14(DTS-4) represent your best estimate of the Initial RVC based on the proceeds from the sale of Canal?

A. Yes, based on my current best estimates of transaction costs and other offsets to the proceeds in calculating the RVC.

Q. Would you update this calculation before filing with the Commission to implement an RVC adjustment to the CTC?

A. Yes. As I explained, Montaup will file a single RVC, if possible, reflecting the proceeds from Canal, Somerset and any other assets or properties sold as part of the "initial divestiture process." If that is not possible, at the time Montaup files its Initial RVC, the calculation would be updated to reflect the most current available proceed and cost information.

Q. How is the RVC flowed through the CTC that Montaup collects from each of the retail companies?

A. As indicated in Exhibit MEC-6(DTS-2), Section 1.1.4(c)(iv),

> "The Net Proceeds from the divestiture including amortization and the pretax return specified in Section 1.1.2 on the unreturned credit balance net of tax impacts shall be credited to the Fixed Component in equal annual amounts over the period commencing on the date the Residual Value Credit is implemented through December 31, 2009."

The levelized calculation is presented as Exhibit MEC-15-17(DTS-5). This exhibit shows the annual flowback of the net mitigation amount and the calculation of the return on the net mitigation amount over the period of 1999 through the year 2009. As stated above, the RVC is to be returned in equal annual amounts, thus, a levelized credit stream was calculated using a discount rate equal to the after-tax weighted average cost of capital.

This levelized stream is depicted at the bottom of Exhibit MEC-15-17 (DTS-5). Exhibit MEC-18-20 (DTS-6) contains the Schedule 1 (CTC calculation) pages that are impacted by the RVC calculation. "Page 12 of 15" for the Rhode Island companies and "Page 13 of 16" for Eastern of Exhibit MEC-18-20 (DTS-6) reflect the RVC applicable to each company as calculated in Exhibit MEC-15-17 (DTS-5). "Page 2" for each company in Exhibit MEC-18-20 (DTS-6) reflects the company-specific share of the net fixed component adjusted for the RVC and "Page 1" is the summary calculation of each company's CTC adjusted for the estimated RVC.

Q. Please discuss the magnitude of your estimated Initial RVC relative to the Company's expectations.

A. This estimate is very much in line with the Company's expectations. The structure of Montaup's power supply and, as a result, its CTC, are such that the RVC is not expected to have a large impact on the CTC. The fixed component of Montaup's CTC is roughly 40% of the total CTC in the first few years, and, of the total net book value underlying the fixed component, Montaup's non-nuclear assets represent only about 20%. Therefore, before accounting for transaction costs and other offsets to sale proceeds, I would expect the impact from an RVC covering the full non-nuclear divestiture to provide a reduction in the CTC only on the order of about 8%. The offsets, as I discussed above, are expected to be significant and will reduce the magnitude of the RVC impact. I would note that in the calculation of the net Initial RVC described above, we have deducted essentially the entire customer liability and other offsets associated with the overall divestiture for costs such as lost revenues, refinancing, and employee benefits.

Therefore, proceeds from remaining asset sales will be available almost entirely to increase the RVC.

VII. TRANSMISSION ISSUES

Q. Please describe the transaction involving Montaup's ownership interest in transmission facilities at the Canal Generating Site.

A. Southern will be buying, from Canal and Montaup, those station and switchyard facilities classified to the generation function and needed to interconnect the Canal units to NEPOOL Pool Transmission Facilities ("PTF") at the Canal Site. Commonwealth, an affiliate of Canal, will purchase Montaup's and Canal's ownership interests in PTF at the Canal Site, and will continue to operate and maintain the Canal Site PTF, along with its other PTF and non-PTF, pursuant to Commission-approved open access transmission tariffs for itself and for NEPOOL. Under the terms of the Bill of Sale and Agreement between Montaup and Commonwealth (Exhibit H), Commonwealth will pay Montaup the net book value of the facilities shown on Montaup's books as of the closing date of the sale to Southern, approximately $600,000. Thereafter, Montaup will have no further interest in transmission facilities at the Canal Site.

Q. What effect will the sale of these facilities have on Montaup's transmission rates?

A. None. Montaup's rates approved in Docket No. OA96-67-000 do not include investments in Canal 2 transmission plant. Montaup's investment in Canal 2 transmission plant is currently being recovered through the CTC.

Q. How will the CTC be adjusted to reflect the sale of these transmission assets?

A. Since the transmission assets are in the CTC, the proceeds from the sale are included in the Initial RVC estimate, and will be included in the calculation of the RVC which will be filed later for Commission approval.

Q. Does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Cambridge Electric Company, Canal Electric Company, Commonwealth Electric Company, Montaup Electric Company, Southern Energy New England, L.L.C., Southern Energy Canal, L.L.C, and Southern Energy Kendall, L.L.C.	)))))))	Docket No. EC98-_____

AFFIDAVIT OF DONALD T. SENA

Commonwealth of Massachusetts)
County of Plymouth) ss.:

Donald T. Sena, being duly sworn, deposes and says:

1. I am the person named in, and who prepared, the foregoing Prepared Direct Testimony of Donald T. Sena. I have read the same, and the facts set forth therein are true and correct to the best of my knowledge, information and belief.

2. If I were asked the questions set forth in the foregoing Prepared Direct Testimony of Donald T. Sena under oath and while a witness in this proceeding, I would give the answers set forth therein in response to those questions.

Donald T. Sena
Donald T. Sena

Sworn to and subscribed before
me this 23 day of July, 1998.

Barbara L. Dantono
Notary Public

My Commission Expires: March 30, 2001

Exhibit MEC-6-BVE
(DTS-2-BVE)

APPENDIX 1

FORMULA FOR CALCULATING CONTRACT TERMINATION CHARGES

MONTAUP ELECTRIC COMPANY
AMENDMENT TO SERVICE AGREEMENT WITH BLACKSTONE VALLEY ELECTRIC COMPANY UNDER FERC ELECTRIC TARIFF, FIRST REVISED VOLUME NO. 1
FORMULA FOR CALCULATING CONTRACT TERMINATION CHARGES

1.1. The Fixed Component of the Contract Termination Charge shall include Blackstone Valley Electric Company's ("Blackstone") 29.13 percent allocated share of Montaup's costs as shown on Schedule 1, Page 2, which shall include:

1.1.1 Revenues sufficient to amortize over a twelve year period commencing on January 1, 1998 and continuing through December 31, 2009 the following plant balances and regulatory assets:

(a) Plant balances shall include unrecovered net book value as shown on Schedule 1, Page 4, Column (7), of the following Montaup generation-related investments as of December 31, 1997,[1] excluding any capital additions made after December 31, 1995:

(i) Somerset Unit 6, Jet 1 and Jet 2 including general plant allocated to generation;
(ii) Montaup's ownership Share of Canal Unit 2, including capital additions past December 31, 1995, but committed prior to that date;
(iii) Montaup's and Newport's ownership share of Wyman Unit 4;
(iv) Montaup's ownership share of Millstone Unit 3;
(v) Montaup's ownership share of Seabrook Unit 1;
(vi) Montaup's Entitlements in the Maine Yankee and Vermont Yankee Units, including the balances for materials and supplies;

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[1] The figures shown on Schedule 1, Page 4, Column (7) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

(vii) Newport's generation related investment in the Diesel Units at Jepson and Eldred;
(viii) Step-up transformers at Montaup generating units which are excluded from Montaup's transmission rates;
(ix) Montaup's non-utility property; and
(x) Generation-related property held for future use including net investment in Somerset Unit 5, through November 1, 1997, per settlement agreement in Docket ER94-1062-000.

(b) Regulatory assets shall include the generation-related unrecovered net book balances shown in Schedule 1, Page 5, Column (2), as of December 31, 1997[2]:

(i) FAS 109;
(ii) Net pension liability/(asset) of Montaup and allocated to Montaup by affiliates to the extent that they exceed 5% of the greater of the total pension benefits obligation or the fair market value of plan assets.
(iii) Unamortized deferred FAS 106 costs;
(iv) Unamortized deferred dredging costs;
(v) Unamortized ITC; and
(vi) Montaup's share of unamortized debt expense recorded on the balance sheet of its parent, Eastern Edison Company.

1.1.2 Revenues sufficient to provide an overall pre-tax return of 11.34 percent based on a combined state and federal income tax rate of 39.225 percent, and Montaup's 1995 year-end capital structure as shown in Schedule 1, Page 14, Column (8), including a return on common equity of 9.2 percent for the period prior to the completion of the initial divestiture process for Montaup's non-nuclear generating

[2] The figures shown on Schedule 1, Page 5, Column (2) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

facilities ("Divestiture Date")[3], and sufficient to provide an overall pretax return of 13.09 percent including a return on common equity of 11.4 percent for the period after the Divestiture Date,[4] multiplied by the average of the beginning and ending balances in each calendar year beginning in 1998 of the sum of the following:

(a) Unrecovered net book value of Montaup's generation investments as defined under 1.1.1(a) above, plus

(b) Unrecovered net book value of generation-related Regulatory Assets as defined under 1.1.1(b) above, excluding the unamortized ITC under 1.1.1(b)(v), less

(c) Deferred Taxes as shown in Schedule 1, Page 13, Column (9), equal to the combined state and federal income tax rate of 39.225 percent, which shall be adjusted for changes in tax laws, multiplied by the sum of:

(i) the unrecovered net book value of Montaup's generation investment, plus

(ii) the unrecovered net book value of generation-related regulatory assets, less

[3] If Montaup sells its non-nuclear generating facilities in more than one transaction, the rights and obligations associated with the divestiture shall be allocated among the transactions using appropriate allocators. In the case of return, the allocator shall be based on the net book value of the sold facility or facilities to total net book value of the non-nuclear generating facilities in Section 1.1.1(a). This percentage allocation shall be applied to the total of plant, regulatory asset balances, and deferred tax balances as set forth below.

[4] The difference between the 11.34 percent and 13.09 percent returns as applied to unamortized balances prior to the Divestiture Date shall be recovered, if divestiture occurs, through an offset to the Residual Value Credit, and the difference between the 11.34 percent and 13.09 percent returns that occurs after the Divestiture Date shall be included in the Reconciliation Account. The 11.34 percent and 13.09 percent returns shall be used as the return wherever a return is referenced throughout this Appendix. However, the 13.09 percent return after the Divestiture Date shall be adjusted in accordance with Section 1.1.4(d). Notwithstanding the above, an equity return of 9.2% will be applied to Montaup's equity investment in the Ocean States Power facility for purposes of estimating Contract Termination Charges under the Amendment.

(iii) the unrecovered balance of generation investment for tax purposes, less
(iv) the unrecovered balance of generation-related regulatory assets for tax purposes.

1.1.3 Revenues sufficient to: (i) amortize over a twelve year period commencing on January 1, 1998 and continuing through December 31, 2009 the generation-related, unrecovered net book balances associated with the FAS 106 Transition Obligation of Montaup and allocated to Montaup by its affiliates[5]; and (ii) pay a return of 7.25 percent equal to the interest rate reflected in the actuarial analysis of the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates multiplied by the outstanding balances remaining for the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates. Following the Divestiture Date, these outstanding balances shall be subject to a one time adjustment as set forth in Section 1.1.4(b) below. At the same time, the interest rate return for the period after the Divestiture Date shall be established using the most current actuarial analysis available at the time, which rate shall remain in place for the remainder of the fixed cost recovery period.

1.1.4 The Fixed Components shall be subject only to the following adjustments:

(a) For each month that the Contract Termination Date is delayed beyond January 1, 1998, Montaup shall adjust the Reconciliation Account in the Variable Component of the Contract Termination Charge by an

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[5] Any FAS 106 Transition Obligation of Montaup and allocated to Montaup by its affiliates that is not allocated to generating facilities shall be deemed transmission related.

amount equal to the difference between the depreciation and amortization expense authorized under the M-14 rate and the depreciation and amortization under Section 1.1.1, together with the associated return computed in accordance with Section 1.1.2 of this Appendix, multiplied by Blackstone's 29.13 percent allocated share. An exhibit showing the difference between depreciation and amortization under the M-14 rate and the Contract Termination Charge is included in Schedule 2.

(b) Following the Divestiture Date and at the time of implementing the Residual Value Credit, Montaup shall reconcile the balances in Sections 1.1.1 and 1.1.3 for Blackstone's 29.13 percent allocated share of (i) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 106 obligation; and (ii) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 87 obligation, but the gains or losses associated with FAS 87 shall be recognized only to the extent that they exceed five percent of the greater of total pension benefits obligation or fair market value of plan assets. Montaup shall fund the FAS 106 and FAS 87 obligations under this Section and Section 1.2.2(f) as rapidly as permitted by the tax law up to the level of revenues collected for this purpose.[6] Any revenues associated with these obligations that cannot be immediately funded shall be put into a separate account on the books to be reserved with the return specified in Section 1.1.3 until tax deductible funding becomes possible. The one-time adjustment associated with FAS 106 and FAS 87, whether positive or negative, shall be subtracted from or added to the schedules for prospective recovery of FAS 106, as appropriate, and amortized with the return specified in Section 1.1.3 over the period between the sale and December 31, 2009. An exhibit showing the reconciliations is included in Schedule 3, page 1. In addition, Montaup shall reconcile the balances for Blackstone's 29.13 percent allocated share of (i) the FAS 109 regulatory asset; and (ii) the general plant allocated to generation, provided, however, that any general plant not allocated to generation shall be functionalized to transmission. The one-time adjustment associated with differences in the balances for FAS 109 and general plant, whether positive or negative, shall be subtracted from or added to the net proceeds reflected in the Residual Value Credit as appropriate and shall be amortized, with the return specified in Section 1.1.2, over the period between the sale and December 31, 2009.

[6] Montaup's post-divestiture FAS 106 or FAS 87 gains or losses recognized on Montaup's books shall be fully reflected in rates to customers and shall neither be retained nor borne by Montaup. Montaup shall propose an allocation of these post-divestiture gains or losses between customers paying Contract Termination Charges and transmission customers.

(c) Montaup has agreed to divest its generating business within six months after the later of the Retail Access Date as defined in the Settlement filed in Docket ER97-3127-000 or the receipt of all governmental approvals and other consents necessary for the divestiture. Within three months after the completion of divestiture or the sale of any property,[7] the cost of which is included in the Contract Termination Charge, Montaup shall implement a Residual Value Credit as a direct offset to the Contract Termination Charges authorized under this Amendment. The Residual Value Credit will be deemed to be fully implemented upon completion of the initial divestiture process for Montaup's non-nuclear generating facilities. Proceeds from the divestiture which are realized after the full implementation of the Residual Value Credit will be reflected in the variable component of the CTC as hereinafter described. The Residual Value Credit to Blackstone shall be calculated as follows:

(i) Blackstone's 29.13 percent allocated share of Total Proceeds[8]

[7] Proceeds, if any, from Montaup's future leases of nuclear entitlements will also be flowed through the Residual Value Credit if such proceeds can be definitively calculated at the time the Residual Value Credit is determined. The proceeds from leases determined after the Residual Value Credit is set will be flowed through the Reconciliation Account as received.

[8] As part of the terms of the Divestiture, Montaup shall require the buyer of the facility to pay Montaup the net book value for all inventories and materials and supplies associated with the generating facility. As a result, inventories and materials and supplies for Montaup's non-nuclear facilities are excluded from the plant balances under Section 1.1.1. and shall be excluded from the calculation of the Residual Value Credit. In addition, the Buyer may assume other obligations that

equal to the sale price and other consideration received by Montaup excluding $15 million[9] which purchasers will be required to pay into an account for employee benefits pursuant to Section 1.2.2(f), less

(ii) The revenues lost or gained by Montaup between July 1, 1997 and the Divestiture Date measured by the difference between the revenues excluding revenues attributable to items included in the Contract Termination Charge or in Montaup's transmission rates, that Montaup would have collected under Rate M-14 had it continued to make the sales to Blackstone under Tariff 1 and the revenues, excluding transmission revenues and Contract Termination Charge revenues, that it actually collected from sales to Blackstone's customers during the period, together with a credit for Blackstone's share of the revenue from sales at no less than market prices made by Montaup to third parties during the period, provided, however, the lost revenues so calculated shall not exceed $0.008 per kilowatthour multiplied by the number of

should be Contract Termination Date

are included in the variable component of the Contract Termination Charge. Montaup reserves its right to revise the variable cost estimates and the amortization of fixed cost components in Schedule 1 to reflect the assignment of obligations to the purchasers, if such revision is necessary to maintain a stable and declining pattern of Contract Termination Charges as offset by the Residual Value Credit.

[9] This figure consists of $11.8 million as shown on Schedule 5 and an estimated $3.2 million for Canal 2 based on Montaup's 25% share of employee costs for Canal Station. The parties agree to use a reasonable actual figure for Canal 2 when available from Canal Electric.

kilowatthours delivered[10] by Blackstone during the period between July 1, 1997 and the Divestiture Date, less

(iii) Blackstone's 29.13 percent allocated share of capital investments demonstrated to be prudently incurred after December 31, 1995, excluded from the plant balances in Section 1.1.1 (a) above,[11] less

(iv) Blackstone's 29.13 percent allocated share of reasonable transaction costs associated with the divestiture including the cost of necessary refinancings, repurchases, and retirements of securities occurring after May 1, 1997.

The Net Proceeds from the divestiture including amortization and the pretax return specified in Section 1.1.2 on the unreturned credit balance net of tax impacts shall be credited to the Fixed Component in equal annual amounts over the period commencing on the date the Residual Value Credit is implemented through December 31, 2009. The Residual Value Credit shall be implemented even if: (i) the Divestiture Date occurs before the Contract

Blackstone

[10] "Delivered", as used herein, refers to the kilowatt hours delivered by Newport other than of purchases from Montaup under Rate M-14.

[11] Montaup's capital investments shall include construction work in progress. The investments in non-nuclear generating facilities during the period January 1, 1996 through May 31, 1997 are shown in Schedule 4. These projects have been reviewed by the parties and are included as an offset to the Residual Value Credit subject only to a further review for the reasonableness of the amounts expended in the construction of the projects under Section 3.5 of the Agreement. Montaup may include additional projects, if any, at the time of the calculation of the Residual Value Credit, subject to the dispute resolution procedures under Section 3.5 of the Agreement.

Termination Date, or (ii) the Residual Value Credit exceeds the Contract Termination Charge in any given year. If for any reason, generation assets which were not sold at the Divestiture Date and therefore were not in the Residual Value Credit but remained in the Contract Termination Charge, are sold at a later date, the proceeds of such a sale will be amortized, with a return as specified in Section 1.1.2, over the remaining fixed component recovery period or over a five year period, whichever period is greater, and credited to the Reconciliation Account as received.

(d) Effective with refinancings, repurchases, and retirements of securities relating to assets being recovered through Contract Termination Charge, Montaup shall flow through the Reconciliation Account the annual effects associated with any differences between the 13.09 percent overall pre-tax return and the actual pre-tax return, calculated using an 11.4 percent return on common equity, attributable to changes in the cost of long-term debt, preferred stock, capital structure or income tax rates, provided that the overall pre-tax return shall not exceed 13.09 percent so long as the yield on 10-year Treasury constant maturities as reported in the Federal Reserve Statistical Release is 9 percent or lower. In the event that the yield on Treasury maturities as so reported exceeds 9 percent, the 13.09 percent overall pre-tax return shall be adjusted to include Montaup's actual cost of long-term debt and preferred stock using an 11.40 percent return on common equity. This reconciliation will apply to the period following the Divestiture Date whether or not securitization has been implemented. Notwithstanding the foregoing, nothing shall require a change in capital structure prior to any financing to take advantage of securitization.

Securitization will be implemented only if it would produce net savings to customers after taking into account all transaction costs including call provisions and prepayments, if applicable. Notwithstanding the above, savings from securitization, (pursuant to the terms of a qualified rate order), will be reflected in the Contract Termination Charge.

Any and all financing savings associated with refinancing related to divestiture and following the implementation of the Residual Value Credit, shall be allocated to the Contract Termination Charge through this paragraph, and shall not be reflected in Montaup's capital structure used for transmission rates. To the extent any financing savings are allocated to transmission rates by FERC, however, they shall not also be allocated to the Contract Termination Charge under this paragraph.

1.2 The Variable Component of the Contract Termination Charge shall include Blackstone's allocated share of the items specified in Section 1.2.2, below adjusted for the Reconciliation Account discussed in Section 1.2.1.

1.2.1 The Variable Component shall be adjusted through a Reconciliation Adjustment in which differences, whether positive or negative, between the estimates for Contract Termination Charge Payments by Blackstone and Blackstone's allocated share of the estimated variable costs listed in Section 1.2.2 below and actual Contract Termination Charge payments by Blackstone and its allocated share of the actual variable costs will be accumulated in a Reconciliation Account and added to or subtracted from the Contract Termination Charge from Montaup to Blackstone. The Reconciliation Account shall also include the adjustments under Sections 1.1.2, note 4, 1.1.4(a) and 1.1.4(d) above. A pretax return equal to that specified in Section 1.1.2 shall be included on any balance in the Reconciliation Account, whether positive or negative.

The Reconciliation Account shall accumulate through December 31, 2000, and shall be used to adjust Montaup's Base Contract Termination Charges to Blackstone on January 1, 2001. Thus, effective January 1, 2001, Montaup shall return or collect Blackstone's allocated share of any outstanding balance in the Reconciliation Account by implementing an adjustment to the Base Contract Termination Charges to Blackstone. Thereafter, the balance including the accumulated return in the Reconciliation Account at the end of a year shall be used to adjust Montaup's Base Contract Termination Charges for the following year. Reconciliation Account adjustments to the Contract Termination Charges shall not cause the Contract Termination Charges to exceed 2.8 cents per kilowatthour. Any deferrals caused by the limitation in the prior sentence shall be carried forward with a return into the next annual adjustment to the Base Contract Termination Charge. Any Reconciliation

Account adjustments occurring prior to January 1, 2001 that would otherwise cause the Contract Termination Charge to increase or decrease by more than 0.2 cent per kilowatthour shall be implemented up to 0.2 cents per kilowatthour. The excess above 0.2 cents per kilowatthour shall be amortized with a return over the three years following January 1, 2001.

1.2.2 Blackstone's 29.13 percent allocated share of the specific cost items included in the Variable Component are set forth in Schedule 1 at page 3. The difference between Blackstone's percent allocated share of the actual variable costs incurred by Montaup and the estimated variable costs in this section shall be included in the Reconciliation Account. The costs included in the Variable Component shall include the following:

(a) Nuclear Decommissioning and Other Post Shutdown Costs shown on Schedule 1, Pages 6 and 7, shall include: (i) all charges, excluding any net incremental decommissioning costs caused by operations after the Retail Access Date, for decommissioning and site restoration assessed to Montaup by the operators of each nuclear electric generating facility specified in Section 1.1.1(a) (iv), (v), and (vi) above, subject to the regulatory authority of the agencies having jurisdiction over the operation and collection of such funds; (ii) all other reasonable post shutdown costs associated with Montaup's entitlements in the units listed in Section 1.1.1(a), (iv), (v), and (vi) above; and (iii) all remaining reasonable costs, including decommissioning costs and unrecovered capital costs, associated with Yankee Rowe and Connecticut Yankee shown on Schedule 1, page 7. Funding for the decommissioning costs will be placed in irrevocable trusts in accordance with NRC regulations. If, upon the completion of decommissioning for any of the above listed nuclear generating facilities, it is determined that there has been an over collection of funds, such over collection will be transferred to Montaup's decommissioning fund for either Millstone 3 or Seabrook 1 pending final disposition of their decommissioning. Once all decommissioning is complete, any over collection will be refunded to Blackstone in the Reconciliation Adjustment. Other post shutdown costs will also be fully reconciled in the Reconciliation Adjustment.

Montaup's share of the Book Value of the Actual Nuclear Core at Shutdown or time of sale, which Montaup has not previously recovered through sales or lease proceeds and the Book Value of Materials and Supply at Shutdown or time of sale, which have not been addressed by other recovery mechanisms, will be recovered with a carrying charge in equal amounts over three years at a pre-tax return provided for in Section 1.1.2.

(b) <u>Above Market Payments to Power Suppliers</u> will be (i) all payments by Montaup for Long-Term Power Supply Contracts less the market value realized from the resale of electricity purchased under the contracts into the wholesale market, plus (ii) Economic Buyout Payments associated with those contracts, less (iii) Credit for Unit Sales Contracts, plus (iv) the Power Contract Buyout Incentive realized.

(i) Long-Term Power Supply Contracts will be the power supply contracts listed below which were in place as of December 31, 1995, between Montaup and a third party supplier, continuing to the termination date of each contract. The Long-Term Supply Contracts include:

(1) Ocean State Power I and II
(2) Canal 1, including transmission wheeling, rental andsupport payments
(3) Northeast Energy Associates, including transmission wheeling payments
(4) Potter 2, including transmission wheeling payments
(5) Cleary 9
(6) McNeil, including transmission wheeling payments
(7) Blackstone Hydro, Inc., including transmission wheeling payments
(8) Hydro Quebec, including AC and DC facilities support payments
(9) Pilgrim, including transmission wheeling, rental and support payments
(10) Bear Swamp Hydro
(11) Green Mountain Power Peakers, including transmission wheeling payments

(ii) Economic Buyout Payments will be all reasonable payments agreed to by Montaup after May 1, 1997 associated with the sale, assignment, disposition or buy down of the Long-Term Power Supply Contracts. Economic Buyout Payments shall be recovered as incurred to the extent that current recovery does not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract. The portion of the Economic Buyout Payment that cannot be recovered currently under the prior sentence shall be deferred and recovered with the return specified in Section 1.1.2 as soon as such recovery will not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract.

For purposes of calculating above market payments in (b)(i) and economic buyout payments in (b)(ii), associated with the long term supply contracts with Ocean State Power I and II, Montaup's total obligation under the contracts will be based on a return on equity of 9.2%.

(iii) Credit for Unit Sales Contracts will be all unit sales contracts entered into by Montaup as of December 31, 1995, for sales from (i) Canal Unit 2 if it is not otherwise subject to market valuation and (ii) Contract Demands to non-affiliates, less the market value of these contracts as shown in Schedule 1, Page 3, Columns (7) through (9).

(iv) Power Contract Buyout Incentive will be the sum of: (a) the Power Contract Buyout Incentive Associated with Canal 2 Divestiture calculated in accordance with Schedule 3, pages 2 and 3; and (b) the Power Contract Buyout Incentive Independent of Divestiture which shall represent 10% of the savings realized by customers as the result of the sale, assignment, disposition or buy down of its power supply contracts occurring outside of the divestiture process. The Power Contract Buyout Incentive Independent of Divestiture shall be determined at the time of the sale, assignment, disposition or buy down. The Buyout Incentive for the Ocean State Power units will be calculated in accordance with Page 4 of Schedule 3. The Total Power Contract Buyout Incentive shall not exceed $3.9 million, stated on a present value basis upon the divestiture using a discount rate equal to the actual pre-tax return in place following completion of post divestiture refinancing as determined under Section 1.1.4(d). Montaup shall document the level of the Power Contract Buyout Incentive in a report, and the amount of the Power Contract Buyout Incentive shall be subject to the dispute resolution procedures set forth under Section 3.5 of the Stipulation and Agreement. The Power Contract Buyout Incentive Associated with Canal 2 Divestiture will be recovered in equal increments over the period from the divestiture through December 31, 2009, with appropriate adjustments for the time value of money, and the Power Contract Buyout Incentive Independent of Divestiture will be recovered in equal increments over the remaining term of the related purchased power contract, with appropriate adjustments for the time value of money.

(c) Above Market Fuel Transportation as shown in Schedule 1, Page 15, Column 10 will be Montaup's continuing long-term payment obligations associated with Capacity Payments to Algonquin Natural Gas Pipeline for Canal 2 less the market value of that capacity. The Market Value of Capacity Payments to Algonquin Natural Gas Pipelines will equal the actual proceeds associated with the sale or assignment or termination of contractual obligations. For the purposes of calculating the Contract Termination Charges, prior to the date that Montaup's contractual entitlements to the pipeline capacity are assigned to a nonaffiliate, the Market Value of Capacity Payments to Algonquin Natural Gas Pipeline shall be deemed to equal the savings associated with actual unit operation on natural gas compared to the unit's avoided operation on oil at prevailing market prices. For illustrative purposes, the amounts shown on page 15 of Schedule 1 reflect a market value which is 50 percent of the capacity payments.

(d) Transmission wheeling, rental and support charges as shown in Schedule 1, Page 3, associated with the transmission of electricity from Montaup's entitlements in Seabrook Unit 1, Connecticut Yankee, Maine Yankee, Millstone Unit 3, Wyman Unit 4, Canal Unit 2, Vermont Yankee, which units are located off of Montaup's transmission system. These wheeling and support payments shall include only costs that are excluded from recovery under Montaup's and NEPOOL's open access transmission tariffs or are not assigned to a purchaser of the unit.

(e) Payments in Lieu of Property Taxes will include all reasonable costs incurred by Montaup or its affiliates associated with payments in lieu of property taxes to the cities and towns in which Montaup owns generating facilities to mitigate the loss of tax revenues that those cities and towns would otherwise incur in connection with restructuring. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciling Account, the Payments in Lieu of Property Taxes are assumed to be zero.

(f) Employee Severance and Retraining Costs as shown in Schedule 1, page 3, Column (13), will include all reasonable costs and expenses incurred by Montaup or its affiliates associated with the adjustment of their workforces in connection with the implementation of retail access, divestiture, or the termination of Montaup's Tariff No 1, including, but not limited to early retirement, severance, retraining and other reasonable costs associated with the implementation of the benefits to employees included in Schedule 5. Montaup shall require purchasers of its generating assets to pay $15 million[12] for the costs under this paragraph incurred by Montaup or its affiliates. In the event that the actual costs incurred under this paragraph are less than $15 million, excluding costs found by FERC to be recoverable in Montaup's transmission rates, Montaup shall flow back the difference to customers in the Reconciliation Account. The procedure established in this paragraph shall be the exclusive method for recovering the costs under

[12] The parties agree that $11.8 million will be reserved for Montaup and EUASC employees and estimate that $3.2 million will be reserved for Canal 2 and paid by the buyer of Canal 2. The Canal 2 figure may be adjusted when actual figures are available from Canal Electric.

this paragraph, and, except in the event of legislation changing required benefits, neither Montaup nor its affiliates shall be able to recover more than $15 million, subject to the Canal 2 adjustment, for these costs. Thus, for the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Employee Severance and Retraining Costs are assumed to be zero and, except in the event of legislation changing required benefits, these costs shall not result in an increase to the Reconciliation Account or to the Contract Termination Charge.

(g) Damages, Costs, or Net Recoveries from claims by or against third parties shall include all damages, costs, or recoveries associated with Montaup's generating business which accrued prior to the date of divestiture and which were not: (i) included in the reserves for generation related, uninsured claims other than claims associated with Environmental Response Costs as of May 21, 1994, plus annual additions to the reserves for uninsured claims in Montaup's M-14 rate, less actual payments out of the reserve for generation related claims during the period from May 21, 1994 through the Contract Termination Date; (ii) assigned to Montaup's successor in interest; (iii) recovered from Montaup's insurance carriers; or (iv) the result of gross negligence. For the purposes of calculating the Base Contract

Termination Charges and the estimate included in the Reconciliation Account, Damages, Costs, or Net Recoveries from claims are assumed to be zero.

(h) Performance Based Rate for Nuclear Units Remaining After Divestiture shall credit value received that is not otherwise reflected in the Residual Value Credit, or recover any payments or costs associated with the sale, lease or disposal of Montaup's minority ownership share of the Seabrook, Millstone #3, and Vermont Yankee Nuclear Units ("PBR Nuclear Units") that are not otherwise reflected in the Residual Value Credit. If Montaup is unable to sell, lease, assign, or otherwise dispose of its PBR Nuclear Units on the terms set forth in the Stipulation and Agreement prior to the Contract Termination Date, the Performance Based Rate shall include 80 percent of the reasonable going forward costs, including variable costs and post-1995 capital additions on a cost of service basis,[13] associated with Montaup's PBR Nuclear Units that are not otherwise recovered in contract termination charges less 80 percent of the revenues from sales of energy or capacity from such units or entitlements that are not otherwise reflected in contract termination charges. The Performance

[13] In the event that the nuclear unit is retired before the end of its license life, the capital addition shall be amortized with a return over the remainder of the license or in accordance with its depreciation schedule, whichever is shorter.

Based Rate shall apply for the period from the Contract Termination Date to the date that Montaup either sells, leases, assigns or otherwise disposes of the PBR Nuclear Units or to the date such units are shutdown. Within six months prior to implementing the Performance Based Rate, Montaup will consult with the Signatories on a performance standard for nuclear safety indicators and will file such performance standard with a maximum potential credit for nonperformance of $250,000. Such sales, if any, shall not be made directly to Blackstone's retail customers, however, Montaup shall retain the right to use its minority shares of the PBR Nuclear Units to fulfill its backstop obligations under the standard offer. For the purpose of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Performance Based Rate for Nuclear Units is assumed to be zero.

(i) Environmental Response Costs defined as:

(i) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Blackstone relating to deposits or waste from divested generating facilities off the site of properties sold, whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv), including material deposited before the Divestiture Date at disposal sites, sites to which material may have migrated from off-site disposal sites, or any off-site location at which generation related material may have been deposited before the Divestiture Date associated with the operation of generating facilities sold pursuant to the divestiture plan;

(ii) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Blackstone relating to deposits and wastes occurring prior to the Divestiture Date whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv) from facilities located within the switchyards for which Montaup will retain a permanent easement on parcels that are otherwise being divested if such costs are not recovered in transmission rates;

(iii) Reasonable and prudently incurred costs associated with the purchase of property that is acquired as part of an overall mitigation and response plan associated with sites identified in paragraphs (i) and (ii);

(iv) The statutes and authorities referenced in paragraphs (i) and (ii) shall be the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), Resource Conservation and Recovery Act (RCRA), Massachusetts G.L. c. 21C and 21E, and Rhode Island General Laws 23-19.14, or any other laws, regulations or orders by courts or governmental authorities, or resulting from claims and contentions arising in tort, breach of contract or violation of law;

(v) Except for property acquired under paragraph (iii), Environmental Response Costs shall not include costs associated with the investigation, testing, remediation, or other liabilities relating to property acquired after the Divestiture Date. Environmental Response Costs recovered under paragraphs (i), (ii), and (iii) shall also be offset by: (i) proceeds from insurance companies related to Environmental Response Costs: (ii) proceeds from the sale of properties purchased under paragraph (iii); and (iii) recoveries from third parties;

(vi) Nothing herein is intended to limit, alter, or otherwise affect any liability of Montaup to governmental authorities or third parties other than the buyer or buyers of Montaup generating facilities under any environmental law including those referenced in paragraph (iv).

Exhibit MEC-7-NEC
(DTS-2-NEC)

APPENDIX 1

FORMULA FOR CALCULATING CONTRACT TERMINATION CHARGES

Appendix 1

MONTAUP ELECTRIC COMPANY
AMENDMENT TO SERVICE AGREEMENT WITH
NEWPORT ELECTRIC CORPORATION UNDER
FERC ELECTRIC TARIFF, FIRST REVISED VOLUME NO. 1
FORMULA FOR CALCULATING CONTRACT
TERMINATION CHARGES

1.1 The Fixed Component of the Contract Termination Charge shall include Newport Electric Corporation's ("Newport") 11.85 percent allocated share of Montaup's costs as shown on Schedule 1, Page 2, which shall include:

1.1.1 Revenues sufficient to amortize over a twelve year period commencing on January 1, 1998 and continuing through December 31, 2009 the following plant balances and regulatory assets:

(a) Plant balances shall include unrecovered net book value as shown on Schedule 1, Page 4, Column (7), of the following Montaup generation-related investments as of December 31, 1997,[1] excluding any capital additions made after December 31, 1995:

(i) Somerset Unit 6, Jet 1 and Jet 2 including general plant allocated to generation;
(ii) Montaup's ownership Share of Canal Unit 2, including capital additions past December 31, 1995, but committed prior to that date;
(iii) Montaup's and Newport's ownership share of Wyman Unit 4;
(iv) Montaup's ownership share of Millstone Unit 3;
(v) Montaup's ownership share of Seabrook Unit 1;
(vi) Montaup's Entitlements in the Maine Yankee and Vermont Yankee Units, including the balances for materials and supplies;

[1] The figures shown on Schedule 1, Page 4, Column (7) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

(vii) Newport's generation related investment in the Diesel Units at Jepson and Eldred;
(viii) Step-up transformers at Montaup generating units which are excluded from Montaup's transmission rates;
(ix) Montaup's non-utility property; and
(x) Generation-related property held for future use including net investment in Somerset Unit 5, through November 1, 1997, per settlement agreement in Docket ER94-1062-000.

(b) Regulatory assets shall include the generation-related unrecovered net book balances shown in Schedule 1, Page 5, Column (2), as of December 31, 1997[2]:

(i) FAS 109:
(ii) Net pension liability/(asset) of Montaup and allocated to Montaup by affiliates to the extent that they exceed 5% of the greater of the total pension benefits obligation or the fair market value of plan assets.
(iii) Unamortized deferred FAS 106 costs;
(iv) Unamortized deferred dredging costs;
(v) Unamortized ITC; and
(vi) Montaup's share of unamortized debt expense recorded on the balance sheet of its parent, Eastern Edison Company.

1.1.2 Revenues sufficient to provide an overall pre-tax return of 11.34 percent based on a combined state and federal income tax rate of 39.225 percent, and Montaup's 1995 year-end capital structure as shown in Schedule 1. Page 14, Column (8), including a return on common equity of 9.2 percent for the period prior to the completion of the initial divestiture process for Montaup's non-nuclear generating

[2] The figures shown on Schedule 1, Page 5, Column (2) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

facilities ("Divestiture Date")[3], and sufficient to provide an overall pretax return of 13.09 percent including a return on common equity of 11.4 percent for the period after the Divestiture Date,[4] multiplied by the average of the beginning and ending balances in each calendar year beginning in 1998 of the sum of the following:

(a) Unrecovered net book value of Montaup's generation investments as defined under 1.1.1(a) above, plus

(b) Unrecovered net book value of generation-related Regulatory Assets as defined under 1.1.1(b) above, excluding the unamortized ITC under 1.1.1(b)(v), less

(c) Deferred Taxes as shown in Schedule 1, Page 13, Column (9), equal to the combined state and federal income tax rate of 39.225 percent, which shall be adjusted for changes in tax laws, multiplied by the sum of:

(i) the unrecovered net book value of Montaup's generation investment, plus
(ii) the unrecovered net book value of generation-related regulatory assets, less

[3] If Montaup sells its non-nuclear generating facilities in more than one transaction, the rights and obligations associated with the divestiture shall be allocated among the transactions using appropriate allocators. In the case of return, the allocator shall be based on the net book value of the sold facility or facilities to total net book value of the non-nuclear generating facilities in Section 1.1.1(a). This percentage allocation shall be applied to the total of plant, regulatory asset balances, and deferred tax balances as set forth below.

[4] The difference between the 11.34 percent and 13.09 percent returns as applied to unamortized balances prior to the Divestiture Date shall be recovered, if divestiture occurs, through an offset to the Residual Value Credit, and the difference between the 11.34 percent and 13.09 percent returns that occurs after the Divestiture Date shall be included in the Reconciliation Account. The 11.34 percent and 13.09 percent returns shall be used as the return wherever a return is referenced throughout this Appendix. However, the 13.09 percent return after the Divestiture Date shall be adjusted in accordance with Section 1.1.4(d). Notwithstanding the above, an equity return of 9.2% will be applied to Montaup's equity investment in the Ocean States Power facility for purposes of estimating Contract Termination Charges under the Amendment.

(iii) the unrecovered balance of generation investment for tax purposes, less
(iv) the unrecovered balance of generation-related regulatory assets for tax purposes.

1.1.3 Revenues sufficient to: (i) amortize over a twelve year period commencing on January 1, 1998 and continuing through December 31, 2009 the generation-related, unrecovered net book balances associated with the FAS 106 Transition Obligation of Montaup and allocated to Montaup by its affiliates[5]; and (ii) pay a return of 7.25 percent equal to the interest rate reflected in the actuarial analysis of the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates multiplied by the outstanding balances remaining for the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates. Following the Divestiture Date, these outstanding balances shall be subject to a one time adjustment as set forth in Section 1.1.4(b) below. At the same time, the interest rate return for the period after the Divestiture Date shall be established using the most current actuarial analysis available at the time, which rate shall remain in place for the remainder of the fixed cost recovery period.

1.1.4 The Fixed Components shall be subject only to the following adjustments:

(a) For each month that the Contract Termination Date is delayed beyond January 1, 1998, Montaup shall adjust the Reconciliation Account in

[5] Any FAS 106 Transition Obligation of Montaup and allocated to Montaup by its affiliates that is not allocated to generating facilities shall be deemed transmission related.

revenues collected for this purpose.[6] Any revenues associated with these obligations that cannot be immediately funded shall be put into a separate account on the books to be reserved with the return specified in Section 1.1.3 until tax deductible funding becomes possible. The one-time adjustment associated with FAS 106 and FAS 87, whether positive or negative, shall be subtracted from or added to the schedules for prospective recovery of FAS 106, as appropriate, and amortized with the return specified in Section 1.1.3 over the period between the sale and December 31, 2009. An exhibit showing the reconciliations is included in Schedule 3, page 1. In addition, Montaup shall reconcile the balances for Newport's 11.85 percent allocated share of (i) the FAS 109 regulatory asset; and (ii) the general plant allocated to generation, provided, however, that any general plant not allocated to generation shall be functionalized to transmission. The one-time adjustment associated with differences in the balances for FAS 109 and general plant, whether positive or negative, shall be subtracted from or added to the net proceeds reflected in the Residual Value Credit as appropriate and shall be amortized, with the return specified in Section 1.1.2, over the period between the sale and December 31, 2009.

[6] Montaup's post-divestiture FAS 106 or FAS 87 gains or losses recognized on Montaup's books shall be fully reflected in rates to customers and shall neither be retained nor borne by Montaup. Montaup shall propose an allocation of these post-divestiture gains or losses between customers paying Contract Termination Charges and transmission customers.

(c) Montaup has agreed to divest its generating business within six months after the later of the Retail Access Date as defined in the Settlement filed in Docket ER97-3127-000 or the receipt of all governmental approvals and other consents necessary for the divestiture. Within three months after the completion of divestiture or the sale of any property,[7] the cost of which is included in the Contract Termination Charge, Montaup shall implement a Residual Value Credit as a direct offset to the Contract Termination Charges authorized under this Amendment. The Residual Value Credit will be deemed to be fully implemented upon completion of the initial divestiture process for Montaup's non-nuclear generating facilities. Proceeds from the divestiture which are realized after the full implementation of the Residual Value Credit will be reflected in the variable component of the CTC as hereinafter described. The Residual Value Credit to Newport shall be calculated as follows:

(i) Newport's 11.85 percent allocated share of Total Proceeds[8]

[7] Proceeds, if any, from Montaup's future leases of nuclear entitlements will also be flowed through the Residual Value Credit if such proceeds can be definitively calculated at the time the Residual Value Credit is determined. The proceeds from leases determined after the Residual Value Credit is set will be flowed through the Reconciliation Account as received.

[8] As part of the terms of the Divestiture, Montaup shall require the buyer of the facility to pay Montaup the net book value for all inventories and materials and supplies associated with the generating facility. As a result, inventories and materials and supplies for Montaup's non-nuclear facilities are excluded from the plant balances under Section 1.1.1, and shall be excluded from the calculation of the Residual Value Credit. In addition, the Buyer may assume other obligations that

equal to the sale price and other consideration received by Montaup excluding $15 million[9] which purchasers will be required to pay into an account for employee benefits pursuant to Section 1.2.2(f), less

(ii) The revenues lost or gained by Montaup between July 1, 1997 and the Divestiture Date measured by the difference between the revenues excluding revenues attributable to items included in the Contract Termination Charge or in Montaup's transmission rates, that Montaup would have collected under Rate M-14 had it continued to make the sales to Newport under Tariff 1 and the revenues, excluding transmission revenues and Contract Termination Charge revenues, that it actually collected from sales to Newport's customers during the period, together with a credit for Newport's share of the revenue from sales at no less than market prices made by Montaup to third parties during the period, provided, however, the lost revenues so calculated shall not exceed $0.008 per kilowatthour multiplied by the number of

are included in the variable component of the Contract Termination Charge. Montaup reserves its right to revise the variable cost estimates and the amortization of fixed cost components in Schedule 1 to reflect the assignment of obligations to the purchasers, if such revision is necessary to maintain a stable and declining pattern of Contract Termination Charges as offset by the Residual Value Credit.

[9] This figure consists of $11.8 million as shown on Schedule 5 and an estimated $3.2 million for Canal 2 based on Montaup's 25% share of employee costs for Canal Station. The parties agree to use a reasonable actual figure for Canal 2 when available from Canal Electric.

kilowatthours delivered by Newport during the period between the July 1, 1997 and the Divestiture Date, less

(iii) Newport's 11.85 percent allocated share of capital investments demonstrated to be prudently incurred after December 31, 1995, excluded from the plant balances in Section 1.1.1 (a) above.[10] less

(iv) Newport's 11.85 percent allocated share of reasonable transaction costs associated with the divestiture including the cost of necessary refinancings, repurchases, and retirements of securities occurring after May 1, 1997.

The Net Proceeds from the divestiture including amortization and the pretax return specified in Section 1.1.2 on the unreturned credit balance net of tax impacts shall be credited to the Fixed Component in equal annual amounts over the period commencing on the date the Residual Value Credit is implemented through December 31, 2009. The Residual Value Credit shall be implemented even if: (i) the Divestiture Date occurs before the Contract Termination Date, or (ii) the Residual Value Credit exceeds the Contract

[10] Montaup's capital investments shall include construction work in progress. The investments in non-nuclear generating facilities during the period January 1, 1996 through May 31, 1997 are shown in Schedule 4. These projects have been reviewed by the parties and are included as an offset to the Residual Value Credit subject only to a further review for the reasonableness of the amounts expended in the construction of the projects under Section 3.5 of the Agreement. Montaup may include additional projects, if any, at the time of the calculation of the Residual Value Credit, subject to the dispute resolution procedures under Section 3.5 of the Agreement.

Termination Charge in any given year. If for any reason, generation assets which were not sold at the Divestiture Date and therefore were not in the Residual Value Credit but remained in the Contract Termination Charge, are sold at a later date, the proceeds of such a sale will be amortized, with a return as specified in Section 1.1.2, over the remaining fixed component recovery period or over a five year period, whichever period is greater, and credited to the Reconciliation Account as received.

(d) Effective with refinancings, repurchases, and retirements of securities relating to assets being recovered through Contract Termination Charge, Montaup shall flow through the Reconciliation Account the annual effects associated with any differences between the 13.09 percent overall pre-tax return and the actual pre-tax return, calculated using an 11.4 percent return on common equity, attributable to changes in the cost of long-term debt, preferred stock, capital structure or income tax rates, provided that the overall pre-tax return shall not exceed 13.09 percent so long as the yield on 10-year Treasury constant maturities as reported in the Federal Reserve Statistical Release is 9 percent or lower. In the event that the yield on Treasury maturities as so reported exceeds 9 percent, the 13.09 percent overall pre-tax return shall be adjusted to include Montaup's actual cost of long-term debt and preferred stock using an 11.40 percent return on common equity. This reconciliation will apply to the period following the Divestiture Date whether or not securitization has been implemented. Notwithstanding the foregoing, nothing shall require a change in capital structure prior to any financing to take advantage of securitization.

Securitization will be implemented only if it would produce net savings to customers after taking into account all transaction costs including call provisions and prepayments, if applicable. Notwithstanding the above, savings from securitization, (pursuant to the terms of a qualified rate order), will be reflected in the Contract Termination Charge.

Any and all financing savings associated with refinancing related to divestiture and following the implementation of the Residual Value Credit, shall be allocated to the Contract Termination Charge through this paragraph, and shall not be reflected in Montaup's capital structure used for transmission rates. To the extent any financing savings are allocated to transmission rates by FERC, however, they shall not also be allocated to the Contract Termination Charge under this paragraph.

1.2 The Variable Component of the Contract Termination Charge shall include Newport's allocated share of the items specified in Section 1.2.2, below adjusted for the Reconciliation Account discussed in Section 1.2.1.

1.2.1 The Variable Component shall be adjusted through a Reconciliation Adjustment in which differences, whether positive or negative, between the estimates for Contract Termination Charge Payments by Newport and Newport's allocated share of the estimated variable costs listed in Section 1.2.2 below and actual Contract Termination Charge payments by Newport and its allocated share of the actual variable costs will be accumulated in a Reconciliation Account and added to or subtracted from the Contract Termination Charge from Montaup to Newport. The Reconciliation Account shall also include the adjustments under Sections 1.1.2, note 4, 1.1.4(a) and 1.1.4(d) above. A pretax return equal to that specified in Section 1.1.2 shall be included on any balance in the Reconciliation Account, whether positive or negative.

The Reconciliation Account shall accumulate through December 31, 2000, and shall be used to adjust Montaup's Base Contract Termination Charges to Newport on January 1, 2001. Thus, effective January 1, 2001, Montaup shall return or collect Newport's allocated share of any outstanding balance in the Reconciliation Account by implementing an adjustment to the Base Contract Termination Charges to Newport. Thereafter, the balance including the accumulated return in the Reconciliation Account at the end of a year shall be used to adjust Montaup's Base Contract Termination Charges for the following year. Reconciliation Account adjustments to the Contract Termination Charges shall not cause the Contract Termination Charges to exceed 2.8 cents per kilowatthour. Any deferrals caused by the limitation in the prior sentence shall be carried forward with a return into the next annual adjustment to the Base Contract Termination Charge. Any Reconciliation Account adjustments occurring prior to January 1, 2001 that would otherwise cause the Contract

Termination Charge to increase or decrease by more than 0.2 cents per kilowatthour shall be implemented up to 0.2 cents per kilowatthour. The excess above 0.2 cents per kilowatthour shall be amortized with a return over the three years following January 1, 2001.

1.2.2 Newport's 11.85 percent allocated share of the specific cost items included in the Variable Component are set forth in Schedule 1 at page 3. The difference between Newport's percent allocated share of the actual variable costs incurred by Montaup and the estimated variable costs in this section shall be included in the Reconciliation Account. The costs included in the Variable Component shall include the following:

(a) Nuclear Decommissioning and Other Post Shutdown Costs shown on Schedule 1, Pages 6 and 7, shall include: (i) all charges, excluding any net incremental decommissioning costs caused by operations after the Retail Access Date, for decommissioning and site restoration assessed to Montaup by the operators of each nuclear electric generating facility specified in Section 1.1.1(a) (iv), (v), and (vi) above, subject to the regulatory authority of the agencies having jurisdiction over the operation and collection of such funds: (ii) all other reasonable post shutdown costs associated with Montaup's entitlements in the units listed in Section 1.1.1(a), (iv), (v), and (vi) above; and (iii) all remaining reasonable costs, including decommissioning costs and unrecovered capital costs, associated with Yankee Rowe and Connecticut Yankee shown on Schedule 1, page 7. Funding for the decommissioning costs will be placed in irrevocable trusts in accordance with NRC regulations. If, upon the completion of decommissioning for any of the above listed nuclear generating facilities, it is determined that there has been an over collection of funds, such over collection will be transferred to Montaup's decommissioning fund for either Millstone 3 or Seabrook 1 pending final disposition of their decommissioning. Once all decommissioning is complete, any over collection will be refunded to Newport in the Reconciliation Adjustment. Other post shutdown costs will also be fully reconciled in the Reconciliation Adjustment.

Montaup's share of the Book Value of the Actual Nuclear Core at Shutdown or time of sale, which Montaup has not previously recovered through sales or lease proceeds and the Book Value of Materials and Supply at Shutdown or time of sale, which have not been addressed by other recovery mechanisms, will be recovered with a carrying charge in equal amounts over three years at a pre-tax return provided for in Section 1.1.2.

(b) <u>Above Market Payments to Power Suppliers</u> will be (i) all payments by Montaup for Long-Term Power Supply Contracts less the market value realized from the resale of electricity purchased under the contracts into the wholesale market, plus (ii) Economic Buyout Payments associated with those contracts, less (iii) Credit for Unit Sales Contracts, plus (iv) the Power Contract Buyout Incentive realized.

(i) Long-Term Power Supply Contracts will be the power supply contracts listed below which were in place as of December 31, 1995, between Montaup and a third party supplier, continuing to the termination date of each contract. The Long-Term Supply Contracts include:

(1) Ocean State Power I and II
(2) Canal 1, including transmission wheeling, rental and support payments
(3) Northeast Energy Associates, including transmission wheeling payments
(4) Potter 2, including transmission wheeling payments
(5) Cleary 9
(6) McNeil, including transmission wheeling payments
(7) Newport Hydro, Inc., including transmission wheeling payments
(8) Hydro Quebec, including AC and DC facilities support payments
(9) Pilgrim, including transmission wheeling, rental and support payments
(10) Bear Swamp Hydro
(11) Green Mountain Power Peakers, including transmission wheeling payments

(ii) Economic Buyout Payments will be all reasonable payments agreed to by Montaup after May 1, 1997 associated with the sale, assignment, disposition or buy down of the Long-Term Power Supply Contracts. Economic Buyout Payments shall be recovered as incurred to the extent that current recovery does not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract. The portion of the Economic Buyout Payment that cannot be recovered currently under the prior sentence shall be deferred and recovered with the return specified in Section 1.1.2 as soon as such recovery will not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract.

For purposes of calculating above market payments in (b)(i)and economic buyout payments in (b)(ii), associated with the long term supply contracts with Ocean State Power I and II, Montaup's total obligation under the contracts will be based on a return on equity of 9.2%.

(iii) Credit for Unit Sales Contracts will be all unit sales contracts entered into by Montaup as of December 31, 1995, for sales from (i) Canal Unit 2 if it is not otherwise subject to market valuation and (ii) Contract Demands to non-affiliates, less the market value of these contracts as shown in Schedule 1, Page 3, Columns (7) through (9).

(iv) Power Contract Buyout Incentive will be the sum of: (a) the Power Contract Buyout Incentive Associated with Canal 2 Divestiture calculated in accordance with Schedule 3, pages 2 and 3; and (b) the Power Contract Buyout Incentive Independent of Divestiture which shall represent 10% of the savings realized by customers as the result of the sale, assignment, disposition or buy down of its power supply contracts occurring outside of the divestiture process. The Power Contract Buyout Incentive Independent of Divestiture shall be determined at the time of the sale, assignment, disposition or buy down. The Buyout Incentive for the Ocean State Power units will be calculated in accordance with Page 4 of Schedule 3. The Total Power Contract Buyout Incentive shall not exceed $ 1.6 million, stated on a present value basis upon the divestiture using a discount rate equal to the actual pre-tax return in place following completion of post divestiture refinancing as determined under Section 1.1.4(d). Montaup shall document the level of the Power Contract Buyout Incentive in a report, and the amount of the Power Contract Buyout Incentive shall be subject to the dispute resolution procedures set forth under Section 3.5 of the Stipulation and Agreement. The Power Contract Buyout Incentive Associated with Canal 2 Divestiture will be recovered in equal increments over the period from the divestiture through December 31, 2009, with appropriate adjustments for the time value of money, and the Power Contract Buyout Incentive Independent of Divestiture will be recovered in equal increments over the remaining term of the related purchased power contract, with appropriate adjustments for the time value of money.

(c) Above Market Fuel Transportation as shown in Schedule 1, Page 15, Column 10 will be Montaup's continuing long-term payment obligations associated with Capacity Payments to Algonquin Natural Gas Pipeline for Canal 2 less the market value of that capacity. The Market Value of Capacity Payments to Algonquin Natural Gas Pipelines will equal the actual proceeds associated with the sale or assignment or termination of contractual obligations. For the purposes of calculating the Contract Termination Charges, prior to the date that Montaup's contractual entitlements to the pipeline capacity are assigned to a nonaffiliate, the Market Value of Capacity Payments to Algonquin Natural Gas Pipeline shall be deemed to equal the savings associated with actual unit operation on natural gas compared to the unit's avoided operation on oil at prevailing market prices. For illustrative purposes, the amounts shown on page 15 of Schedule 1 reflect a market value which is 50 percent of the capacity payments.

(d) Transmission wheeling, rental and support charges as shown in Schedule 1, Page 3, associated with the transmission of electricity from Montaup's entitlements in Seabrook Unit 1, Connecticut Yankee, Maine Yankee, Millstone Unit 3, Wyman Unit 4, Canal Unit 2, Vermont Yankee, which units are located off of Montaup's transmission system. These wheeling and support payments shall include only costs that are excluded from recovery under Montaup's and NEPOOL's open access transmission tariffs or are not assigned to a purchaser of the unit.

(e) Payments in Lieu of Property Taxes will include all reasonable costs incurred by Montaup or its affiliates associated with payments in lieu of property taxes to the cities and towns in which Montaup owns generating facilities to mitigate the loss of tax revenues that those cities and towns would otherwise incur in connection with restructuring. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciling Account, the Payments in Lieu of Property Taxes are assumed to be zero.

(f) Employee Severance and Retraining Costs as shown in Schedule 1, page 3, Column (13), will include all reasonable costs and expenses incurred by Montaup or its affiliates associated with the adjustment of their workforces in connection with the implementation of retail access, divestiture, or the termination of Montaup's Tariff No 1, including, but not limited to early retirement, severance, retraining and other reasonable costs associated with the implementation of the benefits to employees included in Schedule 5. Montaup shall require purchasers of its generating assets to pay $15 million[11] for the costs under this paragraph incurred by Montaup or its affiliates. In the event that the actual costs incurred under this paragraph are less than $15 million, excluding costs found by FERC to be recoverable in Montaup's transmission rates, Montaup shall flow back the difference to customers in the Reconciliation Account. The procedure established in this

[11] The parties agree that $11.8 million will be reserved for Montaup and EUASC employees and estimate that $3.2 million will be reserved for Canal 2 and paid by the buyer of Canal 2. The Canal 2 figure may be adjusted when actual figures are avilable from Canal Electric.

paragraph shall be the exclusive method for recovering the costs under this paragraph, and, except in the event of legislation changing required benefits, neither Montaup nor its affiliates shall be able to recover more than $15 million, subject to the Canal 2 adjustment, for these costs. Thus, for the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Employee Severance and Retraining Costs are assumed to be zero and, except in the event of legislation changing required benefits, these costs shall not result in an increase to the Reconciliation Account or to the Contract Termination Charge.

(g) Damages, Costs, or Net Recoveries from claims by or against third parties shall include all damages, costs, or recoveries associated with Montaup's generating business which accrued prior to the date of divestiture and which were not: (i) included in the reserves for generation related, uninsured claims other than claims associated with Environmental Response Costs as of May 21, 1994, plus annual additions to the reserves for uninsured claims in Montaup's M-14 rate, less actual payments out of the reserve for generation related claims during the period from May 21, 1994 through the Contract Termination Date; (ii) assigned to Montaup's successor in interest; (iii) recovered from Montaup's insurance carriers; or (iv) the result of gross negligence. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, Damages, Costs, or Net Recoveries from claims are assumed to be zero.

(h) Performance Based Rate for Nuclear Units Remaining After Divestiture shall credit value received that is not otherwise reflected in the Residual Value Credit, or recover any payments or costs associated with the sale, lease or disposal of Montaup's minority ownership share of the Seabrook, Millstone #3, and Vermont Yankee Nuclear Units ("PBR Nuclear Units") that are not otherwise reflected in the Residual Value Credit. If Montaup is unable to sell, lease, assign, or otherwise dispose of its PBR Nuclear Units on the terms set forth in the Stipulation and Agreement prior to the Contract Termination Date, the Performance Based Rate shall include 80 percent of the reasonable going forward costs, including variable costs and post-1995 capital additions on a cost of service basis,[12] associated with Montaup's PBR Nuclear Units that are not otherwise recovered in contract termination charges less 80 percent of the revenues from sales of energy or capacity from such units or entitlements that are not

[12] In the event that the nuclear unit is retired before the end of its license life, the capital addition shall be amortized with a return over the remainder of the license or in accordance with its depreciation schedule, whichever is shorter.

otherwise reflected in contract termination charges. The Performance Based Rate shall apply for the period from the Contract Termination Date to the date that Montaup either sells, leases, assigns or otherwise disposes of the PBR Nuclear Units or to the date such units are shutdown. Within six months prior to implementing the Performance Based Rate, Montaup will consult with the Signatories on a performance standard for nuclear safety indicators and will file such performance standard with a maximum potential credit for nonperformance of $250,000. Such sales, if any, shall not be made directly to Newport's retail customers, however, Montaup shall retain the right to use its minority shares of the PBR Nuclear Units to fulfill its backstop obligations under the standard offer. For the purpose of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Performance Based Rate for Nuclear Units is assumed to be zero.

(i) Environmental Response Costs defined as:

(i) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Newport relating to deposits or waste from divested generating facilities off the site of properties sold, whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv), including material deposited before the Divestiture Date at disposal sites, sites to which material may have migrated from off-site disposal sites, or any off-site location at which generation related material may have been deposited before the Divestiture Date associated with the operation of generating facilities sold pursuant to the divestiture plan;

(ii) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Newport relating to deposits and wastes occurring prior to the Divestiture Date whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv) from facilities located within the switchyards for which Montaup will retain a permanent easement on parcels that are otherwise being divested if such costs are not recovered in transmission rates;

(iii) Reasonable and prudently incurred costs associated with the purchase of property that is acquired as part of an overall mitigation and response plan associated with sites identified in paragraphs (i) and (ii);

(iv) The statutes and authorities referenced in paragraphs (i) and (ii) shall be the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), Resource Conservation and Recovery Act (RCRA), Massachusetts G.L. c. 21C and 21E, and Rhode Island General Laws 23-19.14, or any other laws, regulations or orders by courts or governmental authorities, or resulting from claims and contentions arising in tort, breach of contract or violation of law;

(v) Except for property acquired under paragraph (iii), Environmental Response Costs shall not include costs associated with the investigation, testing, remediation, or other liabilities relating to property acquired after the Divestiture Date. Environmental Response Costs recovered under paragraphs (i), (ii), and (iii) shall also be offset by: (i) proceeds from insurance companies related to Environmental Response Costs; (ii) proceeds from the sale of properties purchased under paragraph (iii); and (iii) recoveries from third parties;

(vi) Nothing herein is intended to limit, alter, or otherwise affect any liability of Montaup to governmental authorities or third parties other than the buyer or buyers of Montaup generating facilities under any environmental law including those referenced in paragraph (iv).

APPENDIX I

FORMULA FOR CALCULATING CONTRACT TERMINATION CHARGES

MONTAUP ELECTRIC COMPANY
AMENDMENT TO SERVICE AGREEMENT WITH EASTERN EDISON COMPANY UNDER FERC ELECTRIC TARIFF, FIRST REVISED VOLUME NO. 1
FORMULA FOR CALCULATING CONTRACT TERMINATION CHARGES

1.1 The Fixed Component of the Contract Termination Charge shall include Eastern Edison's 59.02 percent allocated share of Montaup's costs as shown on Schedule 1, Page 2, which shall include:

1.1.1 Revenues sufficient to amortize over a twelve-year period commencing on January 1, 1998 and continuing through December 31, 2009 the following plant balances and regulatory assets:

(a) Plant balances shall include the unrecovered net book value as shown on Schedule 1, Page 5, Column (7), of the following Montaup generation-related investments as of January 1, 1998[1], excluding any capital additions made after December 31, 1995:

(i) Somerset Unit 6, Jet 1, and Jet 2 including general plant allocated to generation;
(ii) Montaup's ownership share of Canal Unit 2, including capital additions past December 31, 1995, but committed prior to that date;
(iii) Montaup and Newport's ownership shares of Wyman Unit 4;
(iv) Montaup's ownership share of Millstone Unit 3;
(v) Montaup's ownership share of Seabrook Unit 1;
(vi) Montaup's Entitlements in the Maine and Vermont Yankee Units including the balances for materials and supplies;

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1 The figures shown on Schedule 1, Page 5, Column (7) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

(vii) Newport's generation related investment in the Diesel Units at Jepson and Eldred;
(viii) Step-up transformers at Montaup generating units which are excluded from Montaup's transmission rates;
(ix) Montaup's non-utility property; and
(x) Generation-related property held for future use, including net investment in Somerset Unit 5, through 11/1/97, per settlement agreement in Docket ER94-1062-000.

(b) Regulatory assets shall include the generation-related unrecovered net book balances shown in Schedule 1, Page 6, Column (2), as of December 31, 1997[2]:

(i) FAS 109; [3]
(ii) Net pension liability/(asset) of Montaup and allocated to Montaup by affiliates to the extent that they exceed 5% of the greater of the total pension benefits obligation or the fair market value of plan assets;
(iii) Unamortized deferred FAS 106 costs;
(iv) Unamortized deferred dredging costs;
(v) Unamortized ITC; and
(vi) Montaup's share of unamortized debt expense recorded on the balance sheet of its parent, Eastern Edison.

1.1.2 Revenues sufficient to provide an overall pre-tax return of 11.12[4] percent based on a combined state and federal income tax rate of 39.225 percent,

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2The figures shown on Schedule 1, page 6, Column 2 are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

3The 1995 FAS109 net asset is different from that included in its 1995 financial statements in that it includes an adjustment of $4.2 million required to correctly reflect deferred tax assets and liabilities at 12/31/95. This adjustment was recorded in 1996 and will be included in the Company's audited financial statements for 1996.

4The 11.12 percent shall be used as the return wherever a return is referenced throughout this Appendix. However, the return so calculated shall be adjusted in accordance with Section 1.1.4(d). An equity return of 9.2% will be used to calculate Montaup's purchased power cost from the Ocean States Power facility for purposes of calculating Contract Termination Charges under the Amendment.

which shall remain fixed through December 31, 2009, on Montaup's 1995 year-end capital structure as shown in Schedule 1, Page 15, including a return on common equity of 8.92 percent, multiplied by the average of the beginning and ending balances in each calendar year beginning in the year of the Contract Termination Date, of the sum of the following:

(a) Unrecovered net book value of Montaup's generation investments as defined under 1.1.1 (a) above, plus

(b) Unrecovered net book value of generation-related Regulatory Assets as defined under 1.1.1 (b) above, excluding the unamortized ITC under 1.1.1(b)(v), less

(c) Deferred Taxes as shown in Schedule 1, Page 14, Column (9), equal to the combined state and federal income tax rate of 39.225 percent, which shall be adjusted for changes in tax laws, multiplied by the sum of:

(i) the unrecovered net book value of Montaup's generation investment, plus
(ii) the unrecovered net book value of generation-related regulatory assets, less
(iii) the unrecovered balance of generation investment for tax purposes, less
(iv) the unrecovered balance of generation-related regulatory assets for tax purposes.

1.1.3 Revenues sufficient to: (i) amortize over a twelve year period commencing on January 1, 1998 and continuing through December 31, 2009 the generation-related, unrecovered net book balances associated with the FAS 106 Transition

Obligation of Montaup and allocated to Montaup by its affiliates[5] and (ii) pay a return of 7.25 percent equal to the interest rate reflected in the actuarial analysis of the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates multiplied by the outstanding balances remaining for the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates. Following the date on which Montaup divests its non-nuclear generating facilities ("Divestiture Date")[6], these outstanding balances shall be subject to a one time adjustment as set forth in Section 1.1.4(b) below. At the same time, the interest rate return for the period after the Divestiture Date shall be established using the most current actuarial analysis available at the time, which rate shall remain in place for the remainder of the fixed cost recovery period.

1.1.4 The Fixed Components shall be subject only to the following adjustments:

(a) For each month that the Contract Termination Date is delayed beyond January 1, 1998, Montaup shall adjust the Reconciliation Account in the Variable Component of the Contract Termination Charge by an amount equal to the difference between depreciation and amortization expense authorized under the M-14 rate or a superseding wholesale rate, if any, and the depreciation and amortization authorized under

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[5]Any FAS 106 Transition Obligation of Montaup and allocated to Montaup by its affiliates that is not allocated to generating facilities shall be deemed transmission related.

[6]If Montaup sells its non-nuclear generating facilities in more than one transaction, the rights and obligations associated with the divestiture shall be allocated among the transactions using appropriate allocators.

Section 1.1.1, together with the associated return computed in accordance with Section 1.1.2 of this Appendix, multiplied by Eastern Edison's 59.02 percent allocated share. An exhibit showing the difference between depreciation and amortization under the M-14 rate and the Contract Termination Charge is included in Schedule 2.

(b) Following the Divestiture Date and the time of implementing the Residual Value Credit, Montaup shall reconcile the balances in Sections 1.1.1 and 1.1.3 for Eastern Edison's 59.02 percent allocated share of (i) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 106 obligation; and (ii) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 87 obligation, but the gains or losses associated with FAS 87 shall be recognized only to the extent that they exceed five percent of the greater of total pension benefits obligation or fair market value of plan assets. Montaup shall fund the FAS 106 and FAS 87 obligations under this Section and Section 1.2.3(f) as rapidly as permitted by the tax law up to the level of revenues collected for this purpose.[7] Any revenues associated with these obligations that cannot be immediately funded shall be put into a separate account on the books to be reserved with the return specified

[7]Montaup's post-divestiture FAS 106 or FAS 87 gains or losses recognized on Montaup's books shall be fully reflected in rates to customers and shall neither be retained nor borne by Montaup.

in Section 1.1.3 until tax deductible funding becomes possible. The one-time adjustment associated with FAS 106 and FAS 87, whether positive or negative, shall be subtracted from or added to the schedules for prospective recovery of FAS 106, as appropriate, and amortized with the return specified in Section 1.1.3 over the period between the sale and December 31, 2009. An exhibit showing the reconciliations is included in Schedule 3, page 1. In addition, Montaup shall reconcile the balances for Eastern Edison's 59.02 percent allocated share of (i) the FAS 109 regulatory asset; and (ii) the general plant allocated to generation, provided, however, that any general plant not allocated to generation shall be functionalized to transmission. The one-time adjustment associated with differences in the balances for FAS 109 and general plant, whether positive or negative, shall be subtracted from or added to the net proceeds reflected in the Residual Value Credit as appropriate and shall be amortized, with the return specified in Section 1.1.2, over the period between the sale and December 31, 2009.

(c) Montaup has agreed to divest its generating business within six months after the later of the Retail Access Date or the receipt of all governmental approvals and other consents necessary for the divestiture. Within three months after the completion of divestiture or the sale of any property[8], the cost of which is included in the Contract Termination Charge, Montaup shall implement a Residual Value Credit as a direct offset to the Contract Termination Charges authorized under this Amendment. The Residual Value Credit will be deemed to be fully implemented upon completion of the initial divestiture process for Montaup's non-nuclear generating facilities. Proceeds from the divestiture which are realized after the full implementation of the Residual Value Credit will be reflected in the variable component of the CTC as hereinafter described. The Residual Value Credit to Eastern Edison shall be calculated as follows:

(i) Eastern Edison's 59.02 percent allocated share of Total Proceeds[9] equal to the sale price and other consideration received by Montaup excluding $15 million[10] which purchasers

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[8]Proceeds, if any, from Montaup's future leases of nuclear entitlements will also be flowed through the Residual Value Credit if such proceeds can be definitively calculated at the time the Residual Value Credit is determined. The proceeds from leases determined after the Residual Value Credit is set will be flowed through the Reconciliation Account as received.

[9]As part of the terms of the Divestiture, Montaup shall require the buyer of the facility to pay Montaup the net book value for all inventories and materials and supplies associated with the generating facility. As a result, inventories and materials and supplies for Montaup's non-nuclear facilities are excluded from the plant balances under Section 1.1.1, and shall be excluded from the calculation of the Residual Value Credit. In addition, the Buyer may assume other obligations that are included in the variable component of the Contract Termination Charge. Montaup reserves its right to revise the variable cost estimates and the amortization of fixed cost components in Schedule 1 to reflect the assignment of obligations to the purchasers, if such revision is necessary to maintain a stable and declining pattern of Contract Termination Charges as offset by the Residual Value Credit.

[10]This figure consists of $11.8 million as shown on Schedule 5 and an estimated $3.2 million for Canal 2 based on Montaup's 25% share of employee costs for Canal Station. The parties agree to use a reasonable actual figure for Canal 2 when available from Canal Electric.

will be required to pay into an account for employee benefits pursuant to Section 1.2.3(f), less

(ii) The revenues lost or gained by Montaup between the Contract Termination Date and the Divestiture Date measured by the difference between the revenues, excluding revenues attributable to items included in the Contract Termination Charge or in Montaup's transmission rates, that Montaup would have collected under Rate M-14 or a superseding wholesale rate, if any, had it continued to make the sales to Eastern Edison under the Tariff and the revenues, excluding transmission revenues and Contract Termination Charge revenues, that it actually collected from sales to Eastern Edison's customers during the period, together with a credit for Eastern Edison's share of the revenue from sales at no less than market prices made by Montaup to third parties, provided, however, the lost revenues so calculated shall not exceed $0.008 per kilowatt-hour times the number of kilowatt-hours delivered by Eastern Edison during the period between the Contract Termination Date and the Divestiture Date. If the Divestiture Date occurs after January 1, 1999, Montaup shall provide a report to FERC and the Signatories setting forth the reasons for the delay, and demonstrating its reasonableness, less

(iii) Eastern Edison's 59.02 percent allocated share of Montaup's capital investments demonstrated to be prudently incurred after December 31, 1995 excluded from the plant balances in Section 1.1.1 (a) above[11], less

(iv) Eastern Edison's 59.02 percent allocated share of reasonable transaction costs associated with the divestiture, including the cost of necessary refinancings, repurchases, and retirements of securities occurring after May 16, 1997.

The Net Proceeds from the divestiture including amortization and the pretax return specified in Section 1.1.2 on the unreturned credit balance net of tax impacts shall be credited to the Fixed Component in equal annual amounts over the period commencing on the date the Residual Value Credit is implemented through December 31, 2009. The Residual Value Credit shall be implemented even if: (i) the Divestiture Date occurs before the Retail Access Date, in which event Eastern Edison shall implement the Wholesale Access Date in accordance with footnote in Section 6.1.1 of the Agreement, or

[11]Montaup's capital investments shall include construction work in progress. The investments in non-nuclear generating facilities during the period January 1, 1996 through May 1, 1997 are shown in Schedule 4. These projects have been reviewed by the parties and are included as an offset to the Residual Value Credit subject only to a further review for the reasonableness of the amounts expended in the construction of the projects under Section 3.5 of the Agreement. Montaup may include additional projects, if any, at the time of the calculation of the Residual Value Credit, subject to the dispute resolution procedures under Section 3.5 of the Agreement.

(ii) the Residual Value Credit exceeds the Contract Termination Charge in any given year. If for any reason, generation assets which were not sold at the Divestiture Date and therefore were not in the Residual Value Credit but remained in the Contract Termination Charge, are sold at a later date, the proceeds of such a sale will be amortized, with a return as specified in Section 1.1.2, over the remaining fixed component recovery period or over a five year period, whichever period is greater, and credited to the Reconciliation Account as received.

(d) Effective with refinancings, repurchases, and retirements of securities related to assets being recovered through the Contract Termination Charge, Montaup shall flow through the Reconciliation Account the annual effects associated with any differences between Montaup's 11.12 percent overall pre-tax return and the actual pre-tax return, calculated using a 8.92 percent return on common equity, attributable to changes in the cost of long-term debt, preferred stock, capital structure or income tax rates, provided that the overall pre-tax return shall not exceed 11.12 percent so long as the yield on 10-year Treasury constant maturities as reported in the Federal Reserve Statistical Release is 9 percent or lower. In the event that the yield on Treasury maturities as so reported exceeds 9 percent, the 11.12 percent overall pre-tax return shall be adjusted to include Montaup's actual cost of long-term debt and preferred stock using a 8.92 percent return on common equity. This reconciliation will apply to the period following the Divestiture Date whether or not securitization has been implemented. Notwithstanding the foregoing, nothing shall require a change in capital structure prior to any financing to take advantage of securitization.

Securitization would be implemented only if it would produce net savings to customers after taking into account all transaction costs including call provisions and prepayments, if applicable.

Notwithstanding the above, savings from securitization, (pursuant to the terms of a qualified rate order), will be reflected in the Contract Termination Charge.

Any and all financing savings associated with refinancing related to divestiture and following the implementation of the Residual Value Credit, shall be allocated to the Contract Termination Charge through this paragraph, and shall not be reflected in Montaup's capital structure used for transmission rates. To the extent any financing savings are allocated to transmission rates by FERC, however, they shall not also be allocated to the Contract Termination Charge under this paragraph.

1.2 The Variable Component of the Contract Termination Charge shall include Eastern Edison's allocated share of the items specified in Section 1.2.3, below adjusted for the Reconciliation Account discussed in Sections 1.2.1 and 1.2.2, below.

1.2.1 The Variable Component shall be adjusted through a Reconciliation Adjustment in which differences, whether positive or negative, between the estimates for Contract Termination Charge Payments by Eastern Edison and Eastern Edison's allocated share of the estimated variable costs listed in Section 1.2.3 below and actual Contract Termination Charge payments by Eastern Edison and its allocated share of the actual variable costs will be accumulated in a Reconciliation Account and added to or subtracted from the Contract Termination Charge from Montaup to Eastern Edison. The Reconciliation Account shall also include the adjustment, if any, under Section 1.1.4(a) above, caused by a deferral in the Contract Termination Date, under Section 1.1.4(b) above for the reconciliations of FAS 106, FAS 87, and FAS 109 balances and under Section 1.1.4(d) above for changes in financing and tax cost as a result of divestiture. A pretax return equal to that specified in Section 1.1.2 shall be included on any balance in the Reconciliation Account, whether positive or negative.

The Reconciliation Account shall accumulate through December 31, 2000, and shall be used to adjust Montaup's Base Contract Termination Charges to Eastern Edison on January 1, 2001. Thus, effective January 1, 2001, Montaup shall return or collect Eastern Edison's allocated share of any outstanding balance in the Reconciliation Account by implementing an adjustment to the Base Contract Termination Charges to Eastern Edison. Thereafter, the balance including the accumulated return in the Reconciliation Account at the end of a year shall be used to adjust Montaup's Base Contract Termination Charges for the following year. Reconciliation Account adjustments to the Contract Termination Charges shall not cause the Contract Termination Charges to exceed 3.04 cents per kilowatt-hour. Any deferrals caused by the limitation in the prior sentence shall be carried forward with a return into the next annual adjustment to the Base Contract Termination Charge. Any Reconciliation Account adjustments occurring prior to January 1, 2001 that would otherwise cause the Contract Termination Charge to increase or decrease by more than 0.2 cents per kilowatthour shall be implemented up to 0.2 cents per kilowatthour. The excess above 0.2 cents per kilottwatt hour shall be amortized with a return over the three years following January 1, 2001.

1.2.2 Through December 31, 2009, the Reconciliation Account shall also include a Contract Termination Charge Mitigation Incentive which shall increase the Variable Cost Component when Montaup mitigates the Contract Termination Charge and reduces the cumulative average of the cents per kilowatt-hour Contract Termination Charge to Eastern Edison below 3.04 cents per kilowatt-hour. The schedule of rewards for each level of thé cumulative average Contract Termination Charge in each year from 2001 through 2009 is shown on Schedule 1, page 4.

1.2.3 Eastern Edison's 59.02 percent allocated share of the specific cost items included in the Variable Component are set forth in Schedule 1, page 3. The difference between Eastern Edison's 59.02 percent allocated share of the actual variable costs incurred by Montaup and the estimated variable costs in this section shall be included in the Reconciliation Account. The costs included in the Variable Component shall include the following:

(a) <u>Nuclear Decommissioning and Other Post-Shutdown Obligations</u> shown on Schedule 1, Pages 7 and 8 shall include : (i) all charges, excluding any net incremental decommissioning costs caused by operations after the Retail Access Date, for decommissioning and site restoration, including Federal Decontamination and Decommissioning, assessed to Montaup by the operators of each nuclear electric generating facility specified in Section 1.1.1 (a) (iv), (v) and (vi) above , subject to the regulatory authority of the agencies having jurisdiction over the operation and collection of such funds; (ii) all other reasonable post shutdown costs associated with Montaup's entitlements in the units listed in Section 1.1.1(a), (iv), (v), and (vi) above; and (iii) all remaining reasonable costs, including decommissioning costs and unrecovered capital costs, associated with Yankee Rowe and Connecticut Yankee shown on Schedule 1, page 8. Funding for the decommissioning costs will be placed in irrevocable trusts in accordance with NRC regulations. If, upon the completion of decommissioning for any of the above listed nuclear generating facilities, it is determined that there has been an over collection of funds, such over collection will be transferred to Montaup's decommissioning fund for either Millstone 3 or Seabrook 1 pending final disposition of their decommissioning. Once all decommissioning is complete, Eastern Edison's allocated share of any over collection will be refunded to Eastern in the Reconciliation Adjustment. Other post shutdown costs will also be fully reconciled in the Reconciliation Adjustment.

Federal Decontamination and Decommissioning will be all charges for decontaminating and decommissioning federal uranium enrichment facilities assessed to Montaup by the operators of each nuclear electric generating facility specified in Section 1.1.1 (a)(iv),(v), and (vi) above as well as the Connecticut Yankee and Yankee Rowe facilities, subject to the regulatory authority of the agencies having jurisdiction over the operation and collection of such funds.

Montaup's share of the Book Value of the Actual Nuclear Core at Shutdown or time of sale, which Montaup has not previously recovered through sales or lease proceeds and the Book Value of Materials and Supply at Shutdown or time of sale, which have not been addressed by other recovery mechanisms, will be recovered with a carrying charge in equal amounts over three years at a pre-tax return provided for in Section 1.1.2.

(b) Above Market Payments to Power Suppliers will be (i) all payments by Montaup for Long-Term Power Supply Contracts less the market value realized from the resale of electricity purchased under the contracts into the wholesale market, plus (ii) Economic Buyout Payments associated with those contracts, less (iii) Credit for Unit Sales Contracts.

(i) Long-Term Power Supply Contracts will be all power supply contracts in place as of December 31, 1995, between Montaup and a third party supplier, continuing to the termination date of each contract. The Long-Term Supply Contracts include:

Ocean State Power I and II
Canal 1, including transmission wheeling, rental and support payments
Northeast Energy Associates, including transmission wheeling payments
Potter 2, including transmission wheeling payments
Cleary 9
McNeil, including transmission wheeling payments
Blackstone Hydro, Inc., including transmission wheeling payments
Hydro Quebec, including AC and DC facility support payments
Pilgrim, including transmission wheeling, rental, and support payments
Bear Swamp Hydro
Green Mountain Power Peakers, including transmission wheeling payments

(ii) Economic Buyout Payments will be all reasonable payments agreed to by Montaup after May 16, 1997 associated with the sale, assignment, disposition or buy down of the Long-Term Power Supply Contracts . Economic Buyout Payments shall be recovered as incurred to the extent that current recovery does not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-

still governed by Reconciliation rec'd. fuel

Term Power Supply Contract. The portion of the Economic Buyout Payment that cannot be recovered currently under the prior sentence shall be deferred and recovered with the return specified in Section 1.1.2 as soon as such recovery will not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract.

For purposes of calculating above market payments in (b)(i) and economic buyout payments in (b)(ii), associated with the long term supply contracts with OcOean State Power I and II, Montaup's total obligation under the contracts will be based on a return on equity of 9.2%.

(iii) Credit for Unit Sales Contracts will be all revenues associated with unit sales contracts entered into by Montaup as of December 31, 1995, for sales from (i) Canal Unit 2, if it is not otherwise subject to market valuation, and (ii) Contract Demands to non-affiliates, less the market value of these contracts as shown in Schedule 1, Page 3, Columns (7) through (9).

(c) Above Market Fuel Transportation as shown in Schedule 1, Page 16, Column 10 will be Montaup's continuing long-term payment obligations associated with Capacity Payments to Algonquin Natural Gas Pipeline for the Canal 2 lateral less the Market Value associated with this obligation. The Market Value of Capacity Payments to Algonquin Natural Gas Pipeline will equal the actual proceeds associated with the sale, assignment or termination of contractual obligations. For the purposes of calculating the Base Contract Termination Charges, prior to the date that Montaup's contractual entitlements to the pipeline capacity are assigned to a nonaffiliate, the Market Value of Capacity Payments to Algonquin Natural Gas Pipelines shall be deemed to equal the savings associated with actual unit operation on natural gas when compared to the unit's avoided operation on oil at prevailing market prices. For illustrative purposes, the amounts shown on page 16 of Schedule 1 reflect a market value which is 50 percent of the capacity payments.

(d) Transmission wheeling, rental and support charges as shown in Schedule 1, Page 3, Column 11 associated with the transmission of electricity from Montaup's entitlements in Seabrook Unit 1, Connecticut Yankee, Maine Yankee, Millstone Unit 3, Wyman Unit 4, Canal Unit 2, Vermont Yankee, which units are located off of Montaup's transmission system. These wheeling and support payments shall include only costs that are excluded from recovery under Montaup's and NEPOOL's open access transmission tariffs or are not assigned to a purchaser of unit.

(e) Payments in Lieu of Property Taxes as shown on Schedule 1, page 3, column (12),will include all reasonable costs incurred by Montaup or its affiliates associated with payments in lieu of property taxes to the cities and towns in which Montaup owns generating facilities to mitigate the loss of tax revenues that those cities and towns would otherwise incur in connection with restructuring. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Payments in Lieu of Property Taxes are assumed to be zero.

(f) Employee Severance and Retraining as shown in Schedule 1, page 3, Column (13), will include all reasonable costs and expenses incurred by Montaup or its affiliates associated with the adjustment of their workforces in connection with the implementation of retail access, divestiture, or the termination of Montaup's Tariff, including, but not limited to, early retirement, severance, retraining and other reasonable costs associated with the implementation of the benefits to employees included in Schedule 5. Montaup shall require purchasers of its generating assets to pay $15 million[12] for the costs under this paragraph incurred by Montaup or its affiliates. In the event that the actual costs incurred under this paragraph are less than $15 million, excluding costs found by FERC to be recoverable in Montaup's transmission rates, Montaup shall flow back the difference to customers in the Reconciliation Account. The procedure established in this paragraph shall be the exclusive method for recovering the costs under this paragraph, and, except in the event of legislation changing required benefits, neither Montaup nor its affiliates shall be able to recover more than $15 million, subject to the Canal 2 adjustment, for these costs. Thus for the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Employee Severance and Retraining Costs are assumed to be zero and, except in the event of legislation changing required benefits, these costs shall not result in an increase to the Reconciliation Account or to the Contract Termination Charge.

[12] The parties agree that $11.8 million will be reserved for Montaup and EUASC employees and estimate that $3.2 million will be reserved for Canal 2 and paid by the buyer of Canal 2. The Canal 2 figure may be adjusted when actual figures are available from Canal Electric.

(g) Damages, Costs, or Net Recoveries from claims by or against third parties shown on Schedule 1, page 3, column (14) shall include all damages, costs, or recoveries associated with Montaup's generating business which accrued prior to the date of divestiture and which were not (i) included in the reserves for generation related, uninsured claims as of May 21, 1994, plus annual additions to the reserves for uninsured claims in Montaup's M-14 rate, less actual payments out of the reserve for generation related claims during the period from May 21, 1994 through the Contract Termination Date; (ii) assigned to Montaup's successor in interest; (iii) recovered from Montaup's insurance carriers; or (iv) the result of gross negligence. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, Damages, Costs, or Net Recoveries from claims are assumed to be zero.

(h) Performance Based Rate for Nuclear Units Remaining After Divestiture shown on Schedule 1, page 3, column (15) shall credit value received that is not otherwise reflected in the Residual Value Credit, or recover any payments or costs associated with the sale, lease or disposal of Montaup's minority ownership share of the Seabrook, Millstone #3, Maine Yankee and Vermont Yankee Nuclear Units ("PBR Nuclear Units") that are not otherwise reflected in the Residual Value Credit. If Montaup is unable to sell, lease, assign, or otherwise dispose of its PBR Nuclear Units on the terms set forth in the Stipulation and Agreement prior to the Contract Termination Date, the Performance Based Rate shall include 80 percent of the reasonable going forward costs, including variable costs and post-1995 capital additions on a cost of service basis[13], associated with Montaup's PBR Nuclear Units that are not otherwise recovered in contract termination charges less 80 percent of the revenues from sales of energy or capacity from such units that are not otherwise reflected in contract termination charges. The Performance Based Rate shall apply for the period from the Contract Termination Date to the date that Montaup either sells, leases, assigns or otherwise disposes of the PBR Nuclear Units or to the date such units are shutdown. Within six months prior to implementing the Performance Based Rate set forth in the prior sentence, Montaup will consult with the parties on a performance standard for nuclear safety indicators and will file such performance standard with a maximum potential credit for nonperformance of $250,000. Such sales, if any, shall not be made directly to Eastern Edison's retail customers, however, Montaup shall retain the right to use its minority shares of the PBR Nuclear Units to fulfill its backstop obligations under the standard offer. For the purpose of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Performance Based Rate for Nuclear Units is assumed to be zero.

(i) Environmental Response Costs defined as:

(i) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or

[13]In the event that the nuclear unit is retired before the end of its license life, the capital addition shall be amortized with a return over the remainder of the license or in accordance with its depreciation schedule, whichever is shorter.

Blackstone relating to deposits or waste from divested generating facilities off the site of properties sold, whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv), including material deposited before the Divestiture Date at disposal sites, sites to which material may have migrated from off-site disposal sites, or any off-site location at which generation related material may have been deposited before the Divestiture Date associated with the operation of generating facilities sold pursuant to the divestiture plan;

(ii) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Blackstone relating to deposits and wastes occurring prior to the Divestiture Date whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv) from facilities located within the switchyards for which Montaup will retain a permanent easement on parcels that are otherwise being divested if such costs are not recovered in transmission rates;

(iii) Reasonable and prudently incurred costs associated with the purchase of property that is acquired as part of an overall mitigation and response plan associated with sites identified in paragraphs (i) and (ii);

(iv) The statutes and authorities referenced in paragraphs (i) and (ii) shall be the Comprehensive Environmental Response, Compensation and

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Liability Act (CERCLA), Resource Conservation and Recovery Act (RCRA), Massachusetts G.L. c. 21C and 21E, and Rhode Island General Laws 23-19.14, or any other laws, regulations or orders by courts or governmental authorities, or resulting from claims and contentions arising in tort, breach of contract or violation of law;

(v) Except for property acquired under paragraph (iii), Environmental Response Costs shall not include costs associated with the investigation, testing, remediation, or other liabilities relating to property acquired after the Divestiture Date. Environmental Response Costs recovered under paragraphs (i), (ii), and (iii) shall also be offset by: (i) proceeds from insurance companies related to Environmental Response Costs; (ii) proceeds from the sale of properties purchased under paragraph (iii); and (iii) recoveries from third parties;

(vi) Nothing herein is intended to limit, alter, or otherwise affect any liability of Montaup to governmental authorities or third parties other than the buyer or buyers of Montaup generating facilities under any environmental law including those referenced in paragraph (iv).

Exhibit MEC-9-BVE
(DTS-3-BVE)

SCHEDULE 1

SUMMARY OF CONTRACT TERMINATION CHARGES

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO BLACKSTONE VALLEY ELECTRIC

YEAR (1)	EST BVE MWH SALES (2)	SHARE OF FIXED COMPONENT $ IN 000 (3)	SHARE OF FIXED COMPONENT CENTS/KWH (4)	SHARE OF VAR COMPONENT $ IN 000 (5)	SHARE OF VAR COMPONENT CENTS/KWH (6)	SHARE OF TOT TERM CHARGE $ IN 000 (7)	BASE CONTRACT TERM CHARG CENTS/KWH (8)
1998	1,293,212	14,900	1.15	23,897	1.85	38,796	3.00
1999	1,309,137	16,084	1.23	23,190	1.77	39,274	3.00
2000	1,329,905	16,899	1.27	22,998	1.73	39,897	3.00
2001	1,346,024	13,060	0.97	23,084	1.72	36,145	2.69
2002	1,360,074	15,070	1.11	19,955	1.47	35,026	2.58
2003	1,377,851	16,099	1.17	17,931	1.30	34,030	2.47
2004	1,399,848	16,895	1.21	16,261	1.16	33,157	2.37
2005	1,423,866	15,343	1.08	17,001	1.19	32,344	2.27
2006	1,452,574	15,967	1.10	15,677	1.08	31,644	2.18
2007	1,471,219	14,203	0.97	16,535	1.12	30,737	2.09
2008	1,493,432	15,041	1.01	14,882	1.00	29,923	2.00
2009	1,512,696	12,836	0.85	16,231	1.07	29,067	1.92
2010	1,534,838	0	0.00	13,437	0.88	13,437	0.88
2011	1,550,396	0	0.00	12,585	0.81	12,585	0.81
2012	1,566,958	0	0.00	7,517	0.48	7,517	0.48
2013	1,597,666	0	0.00	3,988	0.25	3,988	0.25
2014	1,624,096	0	0.00	4,126	0.25	4,126	0.25
2015	1,644,785	0	0.00	2,802	0.17	2,802	0.17
2016	1,671,116	0	0.00	2,758	0.17	2,758	0.17
2017	1,693,977	0	0.00	2,140	0.13	2,140	0.13
2018	1,713,946	0	0.00	1,999	0.12	1,999	0.12
2019	1,739,097	0	0.00	2,018	0.12	2,018	0.12
2020	1,762,428	0	0.00	2,084	0.12	2,084	0.12
2021	1,787,024	0	0.00	1,797	0.10	1,797	0.10
2022	1,811,988	0	0.00	514	0.03	514	0.03
2023	1,837,328	0	0.00	529	0.03	529	0.03
2024	1,863,048	0	0.00	545	0.03	545	0.03
2025	1,889,155	0	0.00	561	0.03	561	0.03
2026	1,915,656	0	0.00	201	0.01	201	0.01
2027	2,011,439	0	0.00	207	0.01	207	0.01
2028	2,112,011	0	0.00	214	0.01	214	0.01
2029	2,217,611	0	0.00	220	0.01	220	0.01

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, P2, COLUMN (8)
(4) COLUMN (3)/COLUMN (2)
(5) SEE SCHEDULE 1, P 3, COLUMN (18)
(6) COLUMN (5)/COLUMN (2)
(7) COLUMN (3) + COLUMN (5)
(8) COLUMN (7)/COLUMN (2)

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
BLACKSTONE VALLEY ELECTRIC COMPANY SHARE (29.13%)
VARIABLE COMPONENT

YEAR END (1)	[illegible] COSTS (2)	TOTAL OBLIGATION (3)	ASSUMED MARKET VALUE (4)	NET EXCESS OVER MARKET (5)	[illegible] (6)	TOTAL OBLIGATION (7)	ASSUMED MARKET VALUE (8)	NET EXCESS OVER MARKET (9)	[illegible] COSTS (10)	[illegible] (11)	[illegible] TAXES (12)	[illegible] COSTS (13)	DAMAGES [illegible] (14)	[illegible] (15)	BASE TOTAL VARIABLE COMPONENT (16)	[illegible] ACCRUAL (17)	[illegible] (18)
1998	[illegible]	42 517	[illegible]	22 454	0	(1 414)	0	(1 414)	[illegible]	[illegible]	0	0	0	0	[illegible]	0	[illegible]
1999	[illegible]	42 565	20 779	[illegible]	0	(1 297)	0	(1 297)	151	[illegible]	0	0	0	0	23 180	0	[illegible]
2000	[illegible]	42 458	21 157	[illegible]	0	(690)	0	(690)	125	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2001	[illegible]	40 575	[illegible]	[illegible]	0	(453)	0	(453)	119	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2002	1 495	[illegible]	[illegible]	[illegible]	0	(453)	0	(453)	107	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2003	[illegible]	[illegible]	15 515	[illegible]	0	(453)	0	(453)	[illegible]	[illegible]	0	0	0	0	17 931	0	[illegible]
2004	1 550	[illegible]	[illegible]	[illegible]	0	(453)	0	(453)	93	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2005	1 500	[illegible]	16 552	15 413	0	(453)	0	(453)	85	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2006	1 576	[illegible]	17 700	[illegible]	0	(453)	0	(453)	77	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2007	[illegible]	32 775	17 585	[illegible]	0	(453)	0	(453)	[illegible]	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2008	647	[illegible]	16 975	[illegible]	0	(453)	0	(453)	61	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2009	509	[illegible]	16 740	[illegible]	0	(453)	0	(453)	54	[illegible]	0	0	0	0	[illegible]	0	[illegible]
2010	[illegible]	[illegible]	[illegible]	[illegible]	0	(453)	0	(453)	45	0	0	0	0	0	12 585	0	[illegible]
2011	570	[illegible]	[illegible]	[illegible]	0	(453)	0	(453)	[illegible]	0	0	0	0	0	[illegible]	0	[illegible]
2012	[illegible]	12 761	[illegible]	[illegible]	0	(453)	0	(453)	0	0	0	0	0	0	[illegible]	0	[illegible]
2013	494	[illegible]	[illegible]	4 017	0	(453)	0	(453)	0	0	0	0	0	0	[illegible]	0	[illegible]
2014	405	[illegible]	[illegible]	[illegible]	0	(453)	0	(453)	0	0	0	0	0	0	[illegible]	0	[illegible]
2015	417	5 894	1 058	[illegible]	0	(453)	0	(453)	0	0	0	0	0	0	[illegible]	0	[illegible]
2016	430	5 950	[illegible]	2 781	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]
2017	443	[illegible]	[illegible]	[illegible]	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]
2018	456	[illegible]	2 715	1 542	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]
2019	470	[illegible]	2 141	1 548	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]
2020	484	[illegible]	2 580	1 400	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]
2021	498	[illegible]	[illegible]	[illegible]	0	0	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]
2022	514	0	0	0	0	0	0	0	0	0	0	0	0	0	514	0	514
2023	529	0	0	0	0	0	0	0	0	0	0	0	0	0	529	0	529
2024	545	0	0	0	0	0	0	0	0	0	0	0	0	0	545	0	545
2025	561	0	0	0	0	0	0	0	0	0	0	0	0	0	561	0	561
2026	201	0	0	0	0	0	0	0	0	0	0	0	0	0	201	0	201
2027	207	0	0	0	0	0	0	0	0	0	0	0	0	0	207	0	207
2028	214	0	0	0	0	0	0	0	0	0	0	0	0	0	214	0	214
2029	220	0	0	0	0	0	0	0	0	0	0	0	0	0	220	0	220

FOOTNOTES
[illegible] THE SAME [illegible]
[illegible]
(18) COLUMN (16) + COLUMN (17)

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE (1)	LOCATION (2)	YEAR(S) PLACED IN SERVICE (3)	ENERGY SOURCE (4)	NET CAPABILITY MW (5)	$ IN 000 1995 (6)	$ IN 000 1997 (7)	APPLICABLE ANNUAL DEPRECIATION FOR 1996 AND BEYOND (8)
FOSSIL FUEL UNITS							
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032	23,716	2,158
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041	35,207	2,917
WYMAN 4	YARMOUTH, ME	1978	OIL	12.2	2,030	1,806	112
NEWPORT DIESELS	JAMESTOWN/ PORTSMOUTH, RI/ YARMOUTH, ME	1961 1978 1978	DIESEL DIESEL OIL	8.8 8.3 4.1	1,803	1,499	152
NUCLEAR UNITS							
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705	160,949	4,878
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45.9	137,749	128,279	4,735
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12.0	3,786 (a)	3,092	347
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31.6	7,439 (a)	6,105	667
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604	604	
- NET INVESTMENT IN SOMERSET UNIT 5					5,860	6,449	(b)
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610	2,610	
			TOTAL	542.6	401,659	370,316	15,966

non. n.k. 71,591

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997).

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF DECEMBER 31, 1995 (1)	BALANCE AS OF DECEMBER 31, 1997 (2)	APPLICABLE AMORTIZATION FOR 1996 AND BEYOND (3)	BASIS FOR DEFERRAL (4)
FAS 109 - ASSET	39,916	37,466	1,225	FERC RATEMAKING POLICY
- LIABILITY	(14,583)	(8,717)	(2,933)	FERC RATEMAKING POLICY
FAS 106 DEFERRAL	1,313	538	387 (a)	FERC RATEMAKING POLICY
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)	FAS 87
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607	FERC RATEMAKING POLICY
UNAMORTIZED ITC	(12,523)	(11,367)	(578)	FERC RATEMAKING POLICY
DREDGING	424	173	125 (b)	FERC RATEMAKING POLICY
TOTAL REG. ASSETS	27,941	28,343	(202)	

(a) REMAINING AMORTIZATION SCHEDULE: 387 IN 1998, 151 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95	9,091
AMORTIZATION AMOUNT (1996 & BEYOND)	534
DISCOUNT RATE	7.25%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
1999	669	509	1,178	6,686
2000	669	460	1,129	6,017
2001	669	412	1,081	5,349
2002	669	364	1,032	4,680
2003	669	315	984	4,011
2004	669	267	935	3,343
2005	669	218	887	2,674
2006	669	170	838	2,006
2007	669	121	790	1,337
2008	669	73	741	669
2009	669	24	693	(0)

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25%
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

(1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	0	0	0	0	0
2002	0	0	0	0	0
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	0	0	0	0
2007	0	0	0	0	0
2008	0	0	0	0	0
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

(1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
1999	621	328	3,102	318	711	2,306	7,386
2000	639	339	3,058	407	713	1,208	6,362
2001	658	349	2,972	408	716	58	5,161
2002	679	359	2,906	409	718	60	5,131
2003	699	370	2,823	456	803	63	5,214
2004	721	382	2,742	457	983	65	5,350
2005	743	394	2,681	585	986	68	5,457
2006	766	405	2,587	587	990	70	5,405
2007	770	409	2,013	578	967	52	4,789
2008	759	406	0	546	510	0	2,221
2009	782	418	0	546	0	0	1,746
2010	806	431	0	710	0	0	1,947
2011	830	444	0	710	0	0	1,984
2012	855	457	0	177	0	0	1,489
2013	880	471	0	0	0	0	1,351
2014	907	485	0	0	0	0	1,392
2015	934	499	0	0	0	0	1,433
2016	962	514	0	0	0	0	1,476
2017	991	530	0	0	0	0	1,521
2018	1,021	546	0	0	0	0	1,567
2019	1,051	562	0	0	0	0	1,613
2020	1,083	579	0	0	0	0	1,662
2021	1,115	596	0	0	0	0	1,711
2022	1,149	614	0	0	0	0	1,763
2023	1,183	633	0	0	0	0	1,816
2024	1,219	652	0	0	0	0	1,871
2025	1,255	671	0	0	0	0	1,926
2026	0	691	0	0	0	0	691
2027	0	712	0	0	0	0	712
2028	0	733	0	0	0	0	733
2029	0	755	0	0	0	0	755

Purchase Power Total $000

	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	HEA	Blackstone Hydro	HQ	GMP	BSH	OSP @ 9.2% ROE	Total
1998	36 042	25 977	3 912	330	3 582	25 446	27 471	12 513	526	10,662	150	550	(1 206)	145 955
1999	35 710	27 181	3 976	339	3 568	25 638	27 005	12 519	528	10 770	0	0	(1 146)	146 086
2000	36 174	27 040	4 023	347	3,612	24 978	27 541	12 612	531	10 096	0	0	(1 089)	145 885
2001	36 184	28 548	4 079	381	3 710	25,995	27 914	8 063	533	6 935	0	0	(1 034)	139 788
2002	35 333	21 448	4 137	378	3 818	27 847	27,097	6 780	536	3 731	0	0	(983)	129 720
2003	35 763	0	4 198	391	3,935	25 332	28 839	6 970	539	3 612	0	0	(934)	107 645
2004	34 010	0	4 261	400	4 057	25 953	27,792	7 290	541	3 508	0	0	(887)	107 833
2005	35 889	0	4 327	423	4 192	26,533	27 430	7,907	544	3 397	0	0	(842)	109 800
2006	34 488	0	4 395	440	4 335	26,001	28,508	8 175	547	3 225	0	0	(800)	109 318
2007	38 141	0	4,466	457	4 485	28,907	28 363	8 815	550	3 068	0	0	(760)	112 512
2008	33 952	0	4 540	476	4,643	30,870	27,976	8,937	553	2 997	0	0	(722)	114 222
2009	36,999	0	4,618	495	4 805	27 074	32,561	9 404	557	2,909	0	0	(686)	118 734
2010	34,533	0	4 696	514	4,969	28,398	29,600	9 479	560	2 823	0	0	(652)	114 970
2011	40,427	0	4,779	535	5,148	0	27,329	10 560	563	2 740	0	0	(303)	91 776
2012	19,300	0	4,865	558	5.331	0	0	10 270	567	2 659	0	0	0	43 608
2013	0	0	4.955	579	5 519	0	0	10 413	571	2,581	0	0	0	24 618
2014	0	0	5 049	602	5,717	0	0	10 841	575	2 505	0	0	0	25 789
2015	0	0	5,146	626	0	0	0	11 453	578	2,432	0	0	0	20 235
2016	0	0	5,247	651	0	0	0	11,580	582	2,360	0	0	0	20 426
2017	0	0	0	0	0	0	0	12 384	586	1,986	0	0	0	14 956
2018	0	0	0	0	0	0	0	12 095	591	1,827	0	0	0	14 813
2019	0	0	0	0	0	0	0	12 512	0	1,669	0	0	0	14 381
2020	0	0	0	0	0	0	0	12,769	0	1,584	0	0	0	14 353
2021	0	0	0	0	0	0	0	13 455	0	0	0	0	0	13 455
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
1999	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	324,157	2,710,592
2000	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	283,092	2,740,313
2001	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	134,017	2,520,452
2002	553,418	441,228	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	2,310,145
2003	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2004	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2005	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2006	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2007	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2008	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2009	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2010	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2011	482,632	0	36,979	10,234	17,420	0	541,959	194,911	5,453	0	1,289,588
2012	184,473	0	36,979	10,234	17,420	0	0	194,911	5,453	0	449,470
2013	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2014	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2015	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2016	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2017	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2018	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2019	0	0	0	0	0	0	0	194,911	0	0	194,911
2020	0	0	0	0	0	0	0	194,911	0	0	194,911
2021	0	0	0	0	0	0	0	194,911	0	0	194,911
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
1999	1,663	1,234	1,555	4,452
2000	0	815	1,555	2,370
2001	0	0	1,555	1,555
2002	0	0	1,555	1,555
2003	0	0	1,555	1,555
2004	0	0	1,555	1,555
2005	0	0	1,555	1,555
2006	0	0	1,555	1,555
2007	0	0	1,555	1,555
2008	0	0	1,555	1,555
2009	0	0	1,555	1,555
2010	0	0	1,555	1,555
2011	0	0	1,555	1,555
2012	0	0	1,555	1,555
2013	0	0	1,555	1,555
2014	0	0	1,555	1,555
2015	0	0	1,555	1,555
2016	0	0	1,555	1,555
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

(1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YNK (6)	VERMONT YNK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
1999	292	138	507	91	214	55	1,297
2000	286	138	488	91	214	55	1,272
2001	280	138	470	91	214	55	1,248
2002	275	138	452	91	214	55	1,225
2003	269	138	435	91	238	61	1,232
2004	264	138	418	91	238	61	1,210
2005	259	138	402	91	238	61	1,189
2006	254	138	386	91	238	61	1,168
2007	249	138	371	91	238	61	1,148
2008	245	138	357	91	238	61	1,130
2009	240	138	443	91	0	61	973

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	31,016	18,907	1,226	51,148	0	51,148
1999	29,236	24,802	1,178	55,216	0	55,216
2000	27,038	29,844	1,129	58,011	0	58,011
2001	25,074	18,679	1,081	44,834	0	44,834
2002	23,200	27,503	1,032	51,735	0	51,735
2003	20,758	33,525	984	55,267	0	55,267
2004	17,868	39,196	935	57,999	0	57,999
2005	14,848	36,936	887	52,671	0	52,671
2006	11,711	42,265	838	54,814	0	54,814
2007	8,475	39,490	790	48,756	0	48,756
2008	5,105	45,788	741	51,635	0	51,635
2009	1,650	41,723	693	44,066	0	44,066

COLUMN NOTES:
(2) See Schedule 1, p. 14, Column (8).
(3) p. 1 Column (7) /.2913 - p. 15 Column (16) - p. 12 Column (2)
- p. 12 Column (4) - p. 12 Column (6) - p. 3 Column (17)/.2913.
(4) See p. 5a, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based on results of actual market valuation.
(7) Columns (5) + (6).

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENT
$ IN 000

YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BOOK BASIS BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	TAX BASIS BALANCE GENERATION RELATED REG. ASSETS (6)	TOTAL TAX BASIS (7)	EXCESS BOOK OVER TAX (8)	DEFERRED TAXES (9)
1997	370,316	28,343	398,659	68,206	0	68,206	330,453	129,620
1998	352,754	26,999	379,752	64,971	0	64,971	314,781	123,473
1999	329,715	25,236	354,951	60,728	0	60,728	294,223	115,409
2000	301,993	23,114	325,106	55,622	0	55,622	269,484	105,705
2001	284,641	21,786	306,427	52,426	0	52,426	254,001	99,632
2002	259,093	19,830	278,924	47,721	0	47,721	231,203	90,689
2003	227,952	17,447	245,398	41,985	0	41,985	203,414	79,789
2004	191,543	14,660	206,203	35,279	0	35,279	170,924	67,045
2005	157,233	12,034	169,267	28,960	0	28,960	140,307	55,036
2006	117,972	9,029	127,001	21,728	0	21,728	105,273	41,293
2007	81,289	6,222	87,511	14,972	0	14,972	72,539	28,453
2008	38,757	2,966	41,723	7,138	0	7,138	34,585	13,566
2009	(0)	(0)	(0)	(0)	0	(0)	(0)	(0)

COLUMN NOTES:
(2) SEE SCHEDULE 1, P. 4 COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, P. 5 COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)	SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT. ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039				
1998	379,752	123,473	256,280	262,659	29,781	1,235	31,016
1999	354,951	115,409	239,542	247,911	28,109	1,128	29,236
2000	325,106	105,705	219,401	229,471	26,018	1,020	27,038
2001	306,427	99,632	206,795	213,098	24,161	913	25,074
2002	278,924	90,689	188,234	197,515	22,395	806	23,200
2003	245,398	79,789	165,609	176,922	20,060	698	20,758
2004	206,203	67,045	139,158	152,384	17,278	591	17,868
2005	169,267	55,036	114,231	126,695	14,365	483	14,848
2006	127,001	41,293	85,708	99,970	11,335	376	11,711
2007	87,511	28,453	59,058	72,383	8,207	269	8,475
2008	41,723	13,566	28,157	43,607	4,944	161	5,105
2009	(0)	(0)	(0)	14,078	1,596	54	1,650

EECo 12/31/95

CAPITAL STRUCTURE			ATWACC	BTWACC
COMMON	48 45%	9.20% (a)	4.46%	7.33%
PFD	5 95%	9.83%	0 58%	0.96%
LTD	45 60%	6.67%	3.04%	3.04%
	100 00%		8.08%	11.338%
TAX RATE				39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, P 13 COLUMN (4)
(3) SEE SCHEDULE 1, P 13 COLUMN (9).
(4) COLUMN (2) - COLUMN (3)
(5) COLUMN (4) PRIOR YEAR+COLUMN (4)/2.
(6) COLUMN (5) x TOTAL RATE OF RETURN.
(7) AVERAGE UNAMORT. ITC (ASSUMING 12 YR SL AMORT OF P. 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7).
(a) PER NEP RI FILING.

MONTAUP

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
~~BLACKSTONE VALLEY ELECTRIC~~ COMPANY SHARE (100%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOMMISS AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS TOTAL OBLIGATION (3)	ASSUMED MARKET VALUE (4)	NET EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS TOTAL OBLIGATION (7)	ASSUMED MARKET VALUE (8)	NET EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN UNITS (11)	PAYMENTS IN LIEU OF PROPERTY TAXES (12)	EMPLOYEE SEVERANCE AND RETRAINING COSTS (13)	DAMAGES COSTS OR NET RECOVERIES FROM CLAIMS (14)	PRE-ECRD UNITS REM AFTER MKT VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)
1998	8,011	145,955	68,872	77,083	0	(4,054)	0	(4,054)	473	1,322	0	0	0	0	82,835
1999	7,386	146,088	71,160	74,928	0	(4,452)	0	(4,452)	451	1,297	0	0	0	0	79,600
2000	6,362	145,885	72,628	73,257	0	(2,370)	0	(2,370)	430	1,272	0	0	0	0	78,951
2001	5,161	139,288	65,306	73,982	0	(1,555)	0	(1,555)	410	1,248	0	0	0	0	79,246
2002	5,131	129,720	66,390	63,330	0	(1,555)	0	(1,555)	373	1,225	0	0	0	0	68,504
2003	5,214	109,645	53,329	56,316	0	(1,555)	0	(1,555)	346	1,232	0	0	0	0	61,553
2004	5,350	107,831	57,331	50,500	0	(1,555)	0	(1,555)	319	1,210	0	0	0	0	55,824
2005	5,457	109,800	56,820	52,980	0	(1,555)	0	(1,555)	291	1,189	0	0	0	0	58,362
2006	5,405	109,318	60,784	48,534	0	(1,555)	0	(1,555)	264	1,168	0	0	0	0	53,816
2007	4,789	112,512	60,369	52,143	0	(1,555)	0	(1,555)	237	1,148	0	0	0	0	56,762
2008	2,221	114,222	65,139	49,083	0	(1,555)	0	(1,555)	209	1,130	0	0	0	0	51,088
2009	1,746	118,734	64,362	54,372	0	(1,555)	0	(1,555)	182	973	0	0	0	0	55,718
2010	1,947	114,920	69,338	45,582	0	(1,555)	0	(1,555)	155	0	0	0	0	0	46,130
2011	1,984	91,778	49,040	42,738	0	(1,555)	0	(1,555)	37	0	0	0	0	0	43,202
2012	1,489	53,608	17,737	35,871	0	(1,555)	0	(1,555)	0	0	0	0	0	0	35,805
2013	1,351	24,618	10,724	13,894	0	(1,555)	0	(1,555)	0	0	0	0	0	0	13,690
2014	1,392	25,309	10,982	14,327	0	(1,555)	0	(1,555)	0	0	0	0	0	0	14,164
2015	1,433	20,235	10,492	9,743	0	(1,555)	0	(1,555)	0	0	0	0	0	0	9,621
2016	1,476	20,426	10,879	9,547	0	(1,555)	0	(1,555)	0	0	0	0	0	0	9,468
2017	1,521	14,956	9,131	5,825	0	0	0	0	0	0	0	0	0	0	7,346
2018	1,567	14,613	9,319	5,294	0	0	0	0	0	0	0	0	0	0	6,861
2019	1,613	14,384	9,069	5,315	0	0	0	0	0	0	0	0	0	0	6,928
2020	1,662	14,353	8,860	5,493	0	0	0	0	0	0	0	0	0	0	7,155
2021	1,711	13,455	8,996	4,459	0	0	0	0	0	0	0	0	0	0	6,170
2022	1,763	0	0	0	0	0	0	0	0	0	0	0	0	0	1,763
2023	1,816	0	0	0	0	0	0	0	0	0	0	0	0	0	1,816
2024	1,871	0	0	0	0	0	0	0	0	0	0	0	0	0	1,871
2025	1,926	0	0	0	0	0	0	0	0	0	0	0	0	0	1,926
2026	691	0	0	0	0	0	0	0	0	0	0	0	0	0	691
2027	712	0	0	0	0	0	0	0	0	0	0	0	0	0	712
2028	733	0	0	0	0	0	0	0	0	0	0	0	0	0	733
2029	755	0	0	0	0	0	0	0	0	0	0	0	0	0	755

Column Notes
(2) Schedule 1, p. 6 Column (6) + Schedule 1, p. 7 Column (8)
(3) Schedule 1, p. 8
(5) Column (3) - Column (4)
(7) See Schedule 1, p. 10 Column (5)
(9) Column (7) - Column (8)
(11) Schedule 1, p. 11 Column (8)
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14) and (15)

SCHEDULE 1

SUMMARY OF CONTRACT TERMINATION CHARGES

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO NEWPORT ELECTRIC COMPANY

YEAR (1)	EST NEC MWH SALES (2)	SHARE OF FIXED COMPONENT $ IN 000 (3)	SHARE OF FIXED COMPONENT CENTS/KWH (4)	SHARE OF VAR. COMPONENT $ IN 000 (5)	SHARE OF VAR. COMPONENT CENTS/KWH (6)	SHARE OF TOT. TERM CHARGE $ IN 000 (7)	BASE CONTRACT TERM CHARG CENTS/KWH (8)
1998	530,586	6,196	1.17	9,721	1.83	15,918	3.00
1999	536,555	6,663	1.24	9,434	1.76	16,097	3.00
2000	544,130	6,968	1.28	9,356	1.72	16,324	3.00
2001	549,613	5,350	0.97	9,391	1.71	14,741	2.68
2002	555,606	6,156	1.11	8,118	1.46	14,274	2.57
2003	563,367	6,569	1.17	7,294	1.29	13,863	2.46
2004	571,358	6,853	1.20	6,615	1.16	13,468	2.36
2005	580,288	6,186	1.07	6,916	1.19	13,102	2.26
2006	589,480	6,372	1.08	6,377	1.08	12,749	2.16
2007	596,369	5,628	0.94	6,726	1.13	12,354	2.07
2008	603,135	5,914	0.98	6,054	1.00	11,968	1.98
2009	609,079	4,974	0.82	6,603	1.08	11,577	1.90
2010	616,061	0	0.00	5,466	0.89	5,466	0.89
2011	622,439	0	0.00	5,119	0.82	5,119	0.82
2012	627,545	0	0.00	3,058	0.49	3,058	0.49
2013	636,621	0	0.00	1,622	0.25	1,622	0.25
2014	643,741	0	0.00	1,678	0.26	1,678	0.26
2015	649,276	0	0.00	1,140	0.18	1,140	0.18
2016	654,269	0	0.00	1,122	0.17	1,122	0.17
2017	661,599	0	0.00	870	0.13	870	0.13
2018	667,717	0	0.00	813	0.12	813	0.12
2019	673,767	0	0.00	821	0.12	821	0.12
2020	680,723	0	0.00	848	0.12	848	0.12
2021	687,311	0	0.00	731	0.11	731	0.11
2022	694,002	0	0.00	209	0.03	209	0.03
2023	700,796	0	0.00	215	0.03	215	0.03
2024	707,697	0	0.00	222	0.03	222	0.03
2025	714,705	0	0.00	228	0.03	228	0.03
2026	721,821	0	0.00	82	0.01	82	0.01
2027	757,912	0	0.00	84	0.01	84	0.01
2028	795,808	0	0.00	87	0.01	87	0.01
2029	835,598	0	0.00	89	0.01	89	0.01

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, P2, COLUMN (8).
(4) COLUMN (3)/COLUMN (2).
(5) SEE SCHEDULE 1, P 3, COLUMN (18)
(6) COLUMN (5)/COLUMN (2).
(7) COLUMN (3) + COLUMN (5).
(8) COLUMN (7)/COLUMN (2).

SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	3,670	2,381	145	6,196	0	6,196
1999	3,449	3,075	140	6,663	0	6,663
2000	3,178	3,656	134	6,968	0	6,968
2001	2,938	2,284	128	5,350	0	5,350
2002	2,711	3,323	122	6,156	0	6,156
2003	2,417	4,036	117	6,569	0	6,569
2004	2,071	4,671	111	6,853	0	6,853
2005	1,712	4,369	105	6,186	0	6,186
2006	1,344	4,928	99	6,372	0	6,372
2007	968	4,566	94	5,628	0	5,628
2008	580	5,247	88	5,914	0	5,914
2009	186	4,706	82	4,974	0	4,974

COLUMN NOTES:
EACH COLUMN REPRESENTS 11.85% OF THE SAME COLUMN NUMBER ON P. 12.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
VARIABLE COMPONENT

YEAR (1)	NUCLEAR DECOMMISSIONING AND OTHER POST-SHUTDOWN COSTS (2)	TOTAL OBLIGATION (3)	POWER CONTRACTS ASSUMED MARKET VALUE (4)	POWER CONTRACTS NET EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR OUT SALES CONTRACTS POWER TOTAL OBLIGATION (7)	CREDIT FOR OUT SALES CONTRACTS ASSUMED MARKET VALUE (8)	CREDIT FOR OUT SALES CONTRACTS NET EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT COSTS (10)	TRANSMISSION SUPPORT OF [illegible] COMMITMENTS (11)	PMTS IN LIEU OF PROP TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES COSTS OR RECOVERIES FROM CLAIMS (14)	CONTINGENT RIGHTS RE MARKET VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	RECONCILIATION ACCOUNT (17)	TOTAL VARIABLE CONTRACT TERMINATION CHARGE (18)
1998	919	17,296	8,161	9,134	0	(575)	0	(575)	56	157	0	0	0	0	9,721	0	9,721
1999	875	17,311	8,472	8,839	0	(520)	0	(520)	53	154	0	0	0	0	9,434	0	9,434
2000	754	17,287	8,906	8,481	0	(289)	0	(289)	51	151	0	0	0	0	9,356	0	9,356
2001	612	16,508	7,731	8,787	0	(184)	0	(184)	49	148	0	0	0	0	9,194	0	9,194
2002	608	15,172	7,867	7,305	0	(184)	0	(184)	44	145	0	0	0	0	8,110	0	8,110
2003	818	12,993	6,310	6,673	0	(184)	0	(184)	41	146	0	0	0	0	7,394	0	7,394
2004	834	12,770	6,786	5,984	0	(184)	0	(184)	38	141	0	0	0	0	6,615	0	6,615
2005	847	13,011	6,735	6,278	0	(184)	0	(184)	34	141	0	0	0	0	6,830	0	6,830
2006	840	12,954	7,201	5,751	0	(184)	0	(184)	31	140	0	0	0	0	6,377	0	6,377
2007	567	11,333	7,154	6,119	0	(184)	0	(184)	28	146	0	0	0	0	6,120	0	6,120
2008	263	11,575	7,719	5,890	0	(184)	0	(184)	25	114	0	0	0	0	6,054	0	6,054
2009	207	14,010	7,827	6,441	0	(184)	0	(184)	22	115	0	0	0	0	5,883	0	5,883
2010	231	13,848	8,207	5,401	0	(184)	0	(184)	19	0	0	0	0	0	5,466	0	5,466
2011	235	10,875	5,811	5,864	0	(184)	0	(184)	4	0	0	0	0	0	5,119	0	5,119
2012	178	5,160	2,102	3,006	0	(184)	0	(184)	0	0	0	0	0	0	3,058	0	3,058
2013	169	2,887	1,271	1,640	0	(184)	0	(184)	0	0	0	0	0	0	1,622	0	1,622
2014	165	2,987	1,299	1,696	0	(184)	0	(184)	0	0	0	0	0	0	1,676	0	1,676
2015	170	2,396	1,243	1,154	0	(184)	0	(184)	0	0	0	0	0	0	1,140	0	1,140
2016	175	2,470	1,289	1,131	0	0	0	0	0	0	0	0	0	0	1,122	0	1,122
2017	180	1,772	1,082	860	0	0	0	0	0	0	0	0	0	0	870	0	870
2018	186	1,732	1,104	627	0	0	0	0	0	0	0	0	0	0	613	0	613
2019	191	1,704	1,074	630	0	0	0	0	0	0	0	0	0	0	621	0	621
2020	197	1,701	1,050	651	0	0	0	0	0	0	0	0	0	0	646	0	646
2021	203	1,594	1,056	528	0	0	0	0	0	0	0	0	0	0	731	0	731
2022	209	0	0	0	0	0	0	0	0	0	0	0	0	0	209	0	209
2023	215	0	0	0	0	0	0	0	0	0	0	0	0	0	215	0	215
2024	222	0	0	0	0	0	0	0	0	0	0	0	0	0	222	0	222
2025	228	0	0	0	0	0	0	0	0	0	0	0	0	0	228	0	228
2026	82	0	0	0	0	0	0	0	0	0	0	0	0	0	82	0	82
2027	84	0	0	0	0	0	0	0	0	0	0	0	0	0	84	0	84
2028	87	0	0	0	0	0	0	0	0	0	0	0	0	0	87	0	87
2029	89	0	0	0	0	0	0	0	0	0	0	0	0	0	89	0	89

COLUMN NOTES
COLUMNS (2) THROUGH (18) REPRESENT 11.85% OF THE SAME COLUMN NUMBER ON P 15
(9) SEE SCHEDULE 2 P 1 COLUMN [illegible]
(18) COLUMN (16) + COLUMN (17)

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE (1)	LOCATION (2)	YEAR(S) PLACED IN SERVICE (3)	ENERGY SOURCE (4)	NET CAPABILITY MW (5)	$ IN 000 1995 (6)	$ IN 000 1997 (7)	APPLICABLE ANNUAL DEPRECIATION FOR 1996 AND BEYOND (8)
FOSSIL FUEL UNITS							
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032	23,716	2,158
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041	35,207	2,917
WYMAN 4	YARMOUTH, ME	1978	OIL	12 2	2,030	1,806	112
NEWPORT DIESELS	JAMESTOWN/ PORTSMOUTH, RI/ YARMOUTH, ME	1961 1978 1978	DIESEL DIESEL OIL	8 8 8 3 4.1	1,803	1,499	152
NUCLEAR UNITS							
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705	160,949	4,878
MILLSTONE III	WATERFORD, CT	1986	NUCLEAR	45 9	137,749	128,279	4,735
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12.0	3,786 (a)	3,092	347
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31 6	7,439 (a)	6,105	667
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604	604	
- NET INVESTMENT IN SOMERSET UNIT 5					5,860	6,449	(b)
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610	2,610	
			TOTAL	542.8	401,659	370,316	15,966

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING FUEL AND MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997)

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF DECEMBER 31, 1995 (1)	DECEMBER 31, 1997 (2)	APPLICABLE AMORTIZATION FOR 1998 AND BEYOND (3)	BASIS FOR DEFERRAL (4)
FAS 109 - ASSET	39,916	37,466	1,225	FERC RATEMAKING POLICY
- LIABILITY	(14,583)	(8,717)	(2,933)	FERC RATEMAKING POLICY
FAS 106 DEFERRAL	1,313	538	387 (a)	FERC RATEMAKING POLICY
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)	FAS 87
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607	FERC RATEMAKING POLICY
UNAMORTIZED ITC	(12,523)	(11,367)	(578)	FERC RATEMAKING POLICY
DREDGING	424	173	125 (b)	FERC RATEMAKING POLICY
TOTAL REG. ASSETS	27,941	28,343	(202)	

(a) REMAINING AMORTIZATION SCHEDULE: 416 IN 1998, 162 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95	9,091
AMORTIZATION AMOUNT (1996 & BEYOND)	534
DISCOUNT RATE	7.25%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
1999	669	509	1,178	6,686
2000	669	460	1,129	6,017
2001	669	412	1,081	5,349
2002	669	364	1,032	4,680
2003	669	315	984	4,011
2004	669	267	935	3,343
2005	669	218	887	2,674
2006	669	170	838	2,006
2007	669	121	790	1,337
2008	669	73	741	669
2009	669	24	693	(0)

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25%
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

(1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	0	0	0	0	0
2002	0	0	0	0	0
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	0	0	0	0
2007	0	0	0	0	0
2008	0	0	0	0	0
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

(1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
1999	621	328	3,102	318	711	2,306	7,386
2000	639	339	3,058	407	713	1,206	6,362
2001	658	349	2,972	408	716	58	5,161
2002	679	359	2,906	409	718	60	5,131
2003	699	370	2,823	456	803	63	5,214
2004	721	382	2,742	457	983	65	5,350
2005	743	394	2,681	585	986	68	5,457
2006	766	405	2,587	587	990	70	5,405
2007	770	409	2,013	578	967	52	4,789
2008	759	406	0	546	510	0	2,221
2009	782	418	0	546	0	0	1,746
2010	806	431	0	710	0	0	1,947
2011	830	444	0	710	0	0	1,984
2012	855	457	0	177	0	0	1,489
2013	880	471	0	0	0	0	1,351
2014	907	485	0	0	0	0	1,392
2015	934	499	0	0	0	0	1,433
2016	962	514	0	0	0	0	1,476
2017	991	530	0	0	0	0	1,521
2018	1,021	546	0	0	0	0	1,567
2019	1,051	562	0	0	0	0	1,613
2020	1,083	579	0	0	0	0	1,662
2021	1,115	596	0	0	0	0	1,711
2022	1,149	614	0	0	0	0	1,763
2023	1,183	633	0	0	0	0	1,816
2024	1,219	652	0	0	0	0	1,871
2025	1,255	671	0	0	0	0	1,926
2026	0	691	0	0	0	0	691
2027	0	712	0	0	0	0	712
2028	0	733	0	0	0	0	733
2029	0	755	0	0	0	0	755

Purchase Power Total $000

	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	GMP	BSH	OSP @ 9.2% ROE	Total
1998	36,042	25,977	3,932	330	3,562	25,440	27,471	12,513	528	10,662	150	550	(1,206)	145,955
1999	35,710	27,181	3,978	339	3,586	25,838	27,005	12,518	528	10,770	0	0	(1,146)	146,088
2000	36,174	27,040	4,023	347	3,612	24,970	27,541	12,032	531	10,098	0	0	(1,089)	145,885
2001	36,184	28,548	4,079	361	3,710	25,995	27,914	8,083	533	6,935	0	0	(1,034)	139,288
2002	35,333	21,448	4,137	376	3,818	27,047	27,097	6,380	536	3,731	0	0	(983)	129,720
2003	35,763	0	4,198	391	3,935	25,332	29,839	6,970	539	3,012	0	0	(934)	109,645
2004	34,910	0	4,261	406	4,057	25,953	27,792	7,790	541	3,508	0	0	(887)	107,831
2005	35,689	0	4,327	423	4,182	26,533	27,430	7,907	544	3,397	0	0	(842)	108,800
2006	34,480	0	4,395	440	4,335	26,001	26,508	8,179	547	3,225	0	0	(800)	109,318
2007	36,141	0	4,466	457	4,485	26,907	26,383	8,815	550	3,008	0	0	(760)	112,512
2008	33,952	0	4,540	478	4,643	30,870	27,976	8,937	553	2,997	0	0	(722)	114,272
2009	36,999	0	4,618	495	4,805	27,074	32,561	8,404	557	2,909	0	0	(686)	118,734
2010	34,533	0	4,698	514	4,969	26,398	29,800	9,479	560	2,823	0	0	(652)	114,820
2011	40,427	0	4,779	535	5,148	0	27,329	10,560	563	2,740	0	0	(303)	91,778
2012	19,380	0	4,865	556	5,331	0	0	10,270	567	2,659	0	0	0	43,608
2013	0	0	4,955	579	5,519	0	0	10,413	571	2,581	0	0	0	24,818
2014	0	0	5,049	602	5,717	0	0	10,841	575	2,505	0	0	0	25,280
2015	0	0	5,148	628	0	0	0	11,453	578	2,432	0	0	0	20,235
2016	0	0	5,747	651	0	0	0	11,588	582	2,380	0	0	0	20,426
2017	0	0	0	0	0	0	0	12,364	586	1,086	0	0	0	14,050
2018	0	0	0	0	0	0	0	12,095	591	1,927	0	0	0	14,613
2019	0	0	0	0	0	0	0	12,512	0	1,609	0	0	0	14,381
2020	0	0	0	0	0	0	0	12,768	0	1,584	0	0	0	14,353
2021	0	0	0	0	0	0	0	13,455	0	0	0	0	0	13,455
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
1999	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	324,157	2,710,592
2000	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	283,092	2,740,313
2001	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	134,017	2,520,452
2002	553,418	441,228	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	2,310,145
2003	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2004	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2005	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2006	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2007	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2008	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2009	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2010	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2011	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,289,508
2012	184,473	0	36,979	10,234	17,420	0	541,959	194,911	5,453	0	449,470
2013	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2014	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2015	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	247,577
2016	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2017	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2018	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2019	0	0	0	0	0	0	0	194,911	5,453	0	194,911
2020	0	0	0	0	0	0	0	194,911	5,453	0	194,911
2021	0	0	0	0	0	0	0	194,911	0	0	194,911
2022	0	0	0	0	0	0	0	194,911	0	0	0
2023	0	0	0	0	0	0	0	194,911	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
1999	1,663	1,234	1,555	4,452
2000	0	815	1,555	2,370
2001	0	0	1,555	1,555
2002	0	0	1,555	1,555
2003	0	0	1,555	1,555
2004	0	0	1,555	1,555
2005	0	0	1,555	1,555
2006	0	0	1,555	1,555
2007	0	0	1,555	1,555
2008	0	0	1,555	1,555
2009	0	0	1,555	1,555
2010	0	0	1,555	1,555
2011	0	0	1,555	1,555
2012	0	0	1,555	1,555
2013	0	0	1,555	1,555
2014	0	0	1,555	1,555
2015	0	0	1,555	1,555
2016	0	0	1,555	1,555
2017	0	0	1,555	1,555
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

(1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YNK (6)	VERMONT YNK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
1999	292	138	507	91	214	55	1,297
2000	286	138	488	91	214	55	1,272
2001	280	138	470	91	214	55	1,248
2002	275	138	452	91	214	55	1,225
2003	269	138	435	91	238	61	1,232
2004	264	138	418	91	238	61	1,210
2005	259	138	402	91	238	61	1,189
2006	254	138	386	91	238	61	1,168
2007	249	138	371	91	238	61	1,148
2008	245	138	357	91	238	61	1,130
2009	240	138	443	91	0	61	973

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	30,970	20,094	1,226	52,290	0	52,290
1999	29,101	25,950	1,178	56,229	0	56,229
2000	26,821	30,854	1,129	58,803	0	58,803
2001	24,796	19,273	1,081	45,149	0	45,149
2002	22,878	28,040	1,032	51,950	0	51,950
2003	20,395	34,059	984	55,437	0	55,437
2004	17,477	39,416	935	57,828	0	57,828
2005	14,451	36,865	887	52,203	0	52,203
2006	11,342	41,588	838	53,768	0	53,768
2007	8,169	38,536	790	47,494	0	47,494
2008	4,894	44,274	741	49,909	0	49,909
2009	1,573	39,711	693	41,977	0	41,977

COLUMN NOTES:
(2) See Schedule 1, p. 14, Column (8).
(3) p. 1 Column (7) / .1185 - p. 15 Column (16) - p. 12 Column (2) - p. 12 Column (4) - p. 12 Column (6) - p. 3 Column (17)/ .1185.
(4) See p. 5a, Column (3).
(6) Sum of Columns (2) through (4).
(7) To be based on results of actual market valuation.
(8) Columns (5) + (6).

NP30BAS2.WK4 10/23/97

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENT
$ IN 000

YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BOOK BASIS BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	TAX BASIS BALANCE GENERATION RELATED REG. ASSETS (6)	TOTAL TAX BASIS (7)	EXCESS BOOK OVER TAX (8)	DEFERRED TAXES (9)
1997	370,316	28,343	398,659	68,206	0	68,206	330,453	129,620
1998	351,651	26,914	378,565	64,768	0	64,768	313,797	123,087
1999	327,546	25,069	352,615	60,328	0	60,328	292,287	114,649
2000	298,886	22,876	321,762	55,050	0	55,050	266,712	104,618
2001	280,983	21,506	302,489	51,752	0	51,752	250,736	98,351
2002	254,937	19,512	274,449	46,955	0	46,955	227,494	89,235
2003	223,300	17,091	240,391	41,128	0	41,128	199,263	78,161
2004	186,686	14,288	200,975	34,384	0	34,384	166,590	65,345
2005	152,442	11,667	164,109	28,077	0	28,077	136,032	53,359
2006	113,810	8,711	122,521	20,982	0	20,982	101,559	39,837
2007	78,015	5,971	83,986	14,369	0	14,369	69,617	27,307
2008	36,888	2,823	39,711	6,794	0	6,794	32,917	12,912
2009	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, P. 4 COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, P. 5 COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)	SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS RETURN ON UNAMORT. ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039				
1998	378,565	123,087	255,478	262,258	29,735	1,235	30,970
1999	352,615	114,649	237,966	246,722	27,974	1,128	29,101
2000	321,762	104,618	217,144	227,555	25,801	1,020	26,821
2001	302,489	98,351	204,137	210,641	23,883	913	24,796
2002	274,449	89,235	185,215	194,676	22,073	806	22,878
2003	240,391	78,161	162,230	173,722	19,697	698	20,395
2004	200,975	65,345	135,630	148,930	16,886	591	17,477
2005	164,109	53,359	110,751	123,190	13,967	483	14,451
2006	122,521	39,837	82,685	96,718	10,966	376	11,342
2007	83,986	27,307	56,678	69,682	7,901	269	8,169
2008	39,711	12,912	26,799	41,739	4,732	161	4,894
2009	0	0	0	13,400	1,519	54	1,573

EECo 12/31/95
CAPITAL STRUCTURE

			ATWACC	BTWACC
COMMON	48.45%	9.20% (a)	4.46%	7.33%
PFD	5.95%	9.83%	0.58%	0.96%
LTD	45.60%	6.67%	3.04%	3.04%
	100 00%		8.08%	11.338%
TAX RATE				39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, P 13 COLUMN (4).
(3) SEE SCHEDULE 1, P 13 COLUMN (9)
(4) COLUMN (2) - COLUMN (3).
(5) COLUMN (4) PRIOR YEAR+COLUMN (4)/2.
(6) COLUMN (5) x TOTAL RATE OF RETURN.
(7) AVERAGE UNAMORT ITC (ASSUMING 12 YR S/L AMORT. OF P. 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7).
(a) PER NEP RI FILING

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (100%)
VARIABLE COMPONENT

			POWER CONTRACTS			CREDIT FOR UNIT SALES CONTRACTS									
YEAR END (1)	NUCLEAR DECOMMISS AND OTHER POST SHUTDOWN COSTS (2)	TOTAL OBLIGATION (3)	ASSUMED MARKET VALUE (4)	NET EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	TOTAL OBLIGATION (7)	ASSUMED MARKET VALUE (8)	NET EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN UNITS (11)	PMTS IN LIEU OF PROP TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES COSTS OR NET RECOVERIES FROM CLAIMS (14)	PURCH OR NUKE UNITS REM AFTER MKT VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)
1998	8,014	145,955	68,872	77,083	0	(4,854)	0	(4,854)	473	1,322	0	0	0	0	82,038
1999	7,386	146,088	71,160	74,928	0	(4,452)	0	(4,452)	451	1,297	0	0	0	0	79,610
2000	6,367	145,885	72,628	73,257	0	(2,370)	0	(2,370)	430	1,272	0	0	0	0	78,951
2001	5,161	139,288	65,306	73,982	0	(1,555)	0	(1,555)	410	1,248	0	0	0	0	79,346
2002	5,131	129,720	66,390	63,330	0	(1,555)	0	(1,555)	373	1,225	0	0	0	0	68,504
2003	5,214	109,645	53,327	56,318	0	(1,555)	0	(1,555)	346	1,232	0	0	0	0	61,553
2004	5,350	107,831	57,331	50,500	0	(1,555)	0	(1,555)	319	1,210	0	0	0	0	55,824
2005	5,457	108,800	56,820	52,000	0	(1,555)	0	(1,555)	281	1,189	0	0	0	0	50,362
2006	5,405	109,318	60,784	48,534	0	(1,555)	0	(1,555)	264	1,166	0	0	0	0	53,816
2007	4,789	112,512	60,369	52,143	0	(1,555)	0	(1,555)	237	1,148	0	0	0	0	56,702
2008	2,221	114,222	65,139	49,083	0	(1,555)	0	(1,555)	209	1,130	0	0	0	0	51,668
2009	1,740	118,734	64,362	54,372	0	(1,555)	0	(1,555)	182	973	0	0	0	0	55,710
2010	1,947	114,920	69,338	45,582	0	(1,555)	0	(1,555)	155	0	0	0	0	0	46,129
2011	1,984	91,776	49,040	42,736	0	(1,555)	0	(1,555)	37	0	0	0	0	0	43,302
2012	1,489	43,608	17,737	25,871	0	(1,555)	0	(1,555)	0	0	0	0	0	0	25,805
2013	1,351	24,816	10,724	13,094	0	(1,555)	0	(1,555)	0	0	0	0	0	0	13,690
2014	1,392	26,289	10,982	14,327	0	(1,555)	0	(1,555)	0	0	0	0	0	0	14,164
2015	1,433	20,235	10,492	9,743	0	(1,555)	0	(1,555)	0	0	0	0	0	0	9,621
2016	1,476	20,426	10,879	9,547	0	(1,555)	0	(1,555)	0	0	0	0	0	0	9,468
2017	1,521	14,956	9,131	5,825	0	0	0	0	0	0	0	0	0	0	7,346
2018	1,567	14,613	9,319	5,294	0	0	0	0	0	0	0	0	0	0	6,861
2019	1,613	14,381	9,066	5,315	0	0	0	0	0	0	0	0	0	0	6,928
2020	1,667	14,353	8,860	5,493	0	0	0	0	0	0	0	0	0	0	7,155
2021	1,711	13,455	8,998	4,458	0	0	0	0	0	0	0	0	0	0	6,170
2022	1,763	0	0	0	0	0	0	0	0	0	0	0	0	0	1,763
2023	1,816	0	0	0	0	0	0	0	0	0	0	0	0	0	1,816
2024	1,871	0	0	0	0	0	0	0	0	0	0	0	0	0	1,871
2025	1,926	0	0	0	0	0	0	0	0	0	0	0	0	0	1,926
2026	691	0	0	0	0	0	0	0	0	0	0	0	0	0	691
2027	712	0	0	0	0	0	0	0	0	0	0	0	0	0	712
2028	733	0	0	0	0	0	0	0	0	0	0	0	0	0	733
2029	755	0	0	0	0	0	0	0	0	0	0	0	0	0	755

Column Notes
(2) Schedule 1, p. 6, Column (6) + Schedule 1, p. 7 Column (8)
(3) Schedule 1, p. 8
(5) Column (3) - Column (4)
(7) See Schedule 1, p. 10 Column (5)
(9) Column (7) - Column (8)
(11) Schedule 1, p. 11, Column (8)
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15)

SCHEDULE 1

SUMMARY OF CONTRACT TERMINATION CHARGES

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO EASTERN EDISON

YEAR (1)	EST. EECO MWH SALES (2)	SHARE OF FIXED COMPONENT $ IN 000 (3)	SHARE OF FIXED COMPONENT CENTS/KWH (4)	SHARE OF VAR. COMPONENT $ IN 000 (5)	SHARE OF VAR. COMPONENT CENTS/KWH (6)	SHARE OF TOT. TERM CHARGE $ IN 000 (7)	BASE CONTRACT TERM CHARG CENTS/KWH (8)
1998	2,657,921	32,384	1.22	48,417	1.82	80,801	3.04
1999	2,706,272	35,286	1.30	46,985	1.74	82,271	3.04
2000	2,764,630	37,448	1.35	46,597	1.69	84,045	3.04
2001	2,803,400	34,186	1.22	46,771	1.67	80,957	2.89
2002	2,834,527	32,583	1.15	40,431	1.43	73,014	2.58
2003	2,878,068	30,980	1.08	36,329	1.26	67,309	2.34
2004	2,927,804	29,378	1.00	32,947	1.13	62,325	2.13
2005	2,980,479	27,775	0.93	34,445	1.16	62,220	2.09
2006	3,042,237	26,172	0.86	31,762	1.04	57,934	1.90
2007	3,078,060	24,569	0.80	33,501	1.09	58,069	1.89
2008	3,125,312	22,966	0.73	30,152	0.96	53,118	1.70
2009	3,162,865	21,363	0.68	32,885	1.04	54,248	1.72
2010	3,207,992	0	0.00	27,225	0.85	27,225	0.85
2011	3,230,420	0	0.00	25,498	0.79	25,498	0.79
2012	3,260,202	0	0.00	15,230	0.47	15,230	0.47
2013	3,330,172	0	0.00	8,080	0.24	8,080	0.24
2014	3,385,866	0	0.00	8,360	0.25	8,360	0.25
2015	3,427,278	0	0.00	5,678	0.17	5,678	0.17
2016	3,480,882	0	0.00	5,588	0.16	5,588	0.16
2017	3,524,399	0	0.00	4,336	0.12	4,336	0.12
2018	3,561,432	0	0.00	4,049	0.11	4,049	0.11
2019	3,616,299	0	0.00	4,089	0.11	4,089	0.11
2020	3,661,777	0	0.00	4,223	0.12	4,223	0.12
2021	3,710,922	0	0.00	3,642	0.10	3,642	0.10
2022	3,760,846	0	0.00	1,041	0.03	1,041	0.03
2023	3,811,564	0	0.00	1,072	0.03	1,072	0.03
2024	3,863,089	0	0.00	1,104	0.03	1,104	0.03
2025	3,915,436	0	0.00	1,137	0.03	1,137	0.03
2026	3,968,619	0	0.00	408	0.01	408	0.01
2027	4,167,050	0	0.00	420	0.01	420	0.01
2028	4,375,402	0	0.00	433	0.01	433	0.01
2029	4,594,173	0	0.00	446	0.01	446	0.01

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, P2, COLUMN (7).
(4) COLUMN (3)/COLUMN (2).
(5) SEE SCHEDULE 1, P 3, COLUMN (18)
(6) COLUMN (5)/COLUMN (2).
(7) COLUMN (3) + COLUMN (5).
(8) COLUMN (7)/COLUMN (2)

SUMMARY OF CONTRACT TERMINATION CHARGES
EASTERN EDISON COMPANY SHARE (59.02%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	17,826	13,834	724	32,384	0	32,384
1999	16,570	18,021	695	35,286	0	35,286
2000	15,016	21,765	666	37,448	0	37,448
2001	13,382	20,167	638	34,186	0	34,186
2002	11,808	20,167	609	32,583	0	32,583
2003	10,233	20,167	581	30,980	0	30,980
2004	8,659	20,167	552	29,378	0	29,378
2005	7,085	20,167	523	27,775	0	27,775
2006	5,510	20,167	495	26,172	0	26,172
2007	3,936	20,167	466	24,569	0	24,569
2008	2,362	20,167	438	22,966	0	22,966
2009	787	20,167	409	21,363	0	21,363

COLUMN NOTES:
EACH COLUMN REPRESENTS 59.02% OF THE SAME COLUMN NUMBER ON P. 13.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
EASTERN EDISON COMPANY SHARE (59.03%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOMMISSIONING COSTS (2)	POWER CONTRACTS: TOTAL OBLIGATION (3)	POWER CONTRACTS: ASSUMED MARKET VALUE (4)	POWER CONTRACTS: NET EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR FIRM SALES CONTRACTS: POWER TOTAL OBLIGATION (7)	CREDIT FOR FIRM SALES CONTRACTS: ASSUMED MARKET VALUE (8)	CREDIT FOR FIRM SALES CONTRACTS: NET EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORTATION COSTS (10)	TRANSMISSION RESERVED CAPACITY COSTS (11)	TAXES RELATED TO PROPERTY TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES COSTS, ENTITLEMENTS & CLAIMS (14)	1997 FAIR VALUE OF PLANT ALTERNATIVE VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	RECLASS ACCOUNT (17)	TOTAL VARIABLE COMPONENT RECOVERABLE (18)
1998	4,728	86,143	40,840	45,494	0	(2,865)	0	(2,865)	279	780	0	0	0	0	48,417	0	48,412
1999	4,159	86,720	41,998	44,221	0	(2,628)	0	(2,620)	264	765	0	0	0	0	48,985	0	48,985
2000	3,755	86,404	42,865	43,236	0	(1,398)	0	(1,399)	254	751	0	0	0	0	46,507	0	46,597
2001	3,096	82,208	38,543	43,664	0	(910)	0	(910)	247	738	0	0	0	0	48,771	0	46,771
2002	3,028	76,589	29,184	37,377	0	(910)	0	(910)	278	723	0	0	0	0	40,431	0	40,431
2003	3,077	64,712	31,075	33,238	0	(910)	0	(910)	204	727	0	0	0	0	38,329	0	36,329
2004	3,158	63,642	33,837	29,805	0	(910)	0	(910)	198	714	0	0	0	0	32,847	0	32,847
2005	3,221	64,819	33,535	31,209	0	(910)	0	(910)	172	702	0	0	0	0	34,443	0	34,445
2006	3,190	64,519	35,875	28,645	0	(910)	0	(910)	150	689	0	0	0	0	31,783	0	31,762
2007	2,820	56,495	35,830	30,775	0	(910)	0	(910)	140	676	0	0	0	0	31,504	0	33,501
2008	1,318	47,414	38,445	28,988	0	(910)	0	(910)	121	667	0	0	0	0	30,133	0	30,152
2009	1,030	70,022	37,880	32,081	0	(910)	0	(910)	107	574	0	0	0	0	33,003	0	32,885
2010	1,148	67,826	40,823	28,002	0	(910)	0	(910)	91	0	0	0	0	0	27,720	0	27,225
2011	1,173	54,106	28,943	25,223	0	(910)	0	(910)	27	0	0	0	0	0	25,498	0	25,498
2012	879	25,737	10,468	16,288	0	(910)	0	(910)	0	0	0	0	0	0	19,738	0	15,781
2013	797	14,538	8,320	8,208	0	(910)	0	(910)	0	0	0	0	0	0	8,095	0	8,081
2014	822	14,920	8,470	8,454	0	(910)	0	(910)	0	0	0	0	0	0	8,366	0	8,360
2015	840	11,941	8,103	5,750	0	(910)	0	(910)	0	0	0	0	0	0	5,870	0	5,670
2016	873	12,055	8,421	5,634	0	(910)	0	(910)	0	0	0	0	0	0	5,500	0	5,548
2017	898	8,827	5,389	3,438	0	0	0	0	0	0	0	0	0	0	4,536	0	4,396
2018	925	8,825	5,500	3,124	0	0	0	0	0	0	0	0	0	0	4,049	0	4,049
2019	852	8,480	5,361	3,137	0	0	0	0	0	0	0	0	0	0	4,889	0	4,005
2020	981	8,471	5,228	3,242	0	0	0	0	0	0	0	0	0	0	4,223	0	4,223
2021	1,010	2,941	5,309	2,832	0	0	0	0	0	0	0	0	0	0	3,042	0	3,842
2022	1,041	0	0	0	0	0	0	0	0	0	0	0	0	0	1,041	0	1,041
2023	1,072	0	0	0	0	0	0	0	0	0	0	0	0	0	1,072	0	1,072
2024	1,104	0	0	0	0	0	0	0	0	0	0	0	0	0	1,104	0	1,104
2025	1,137	0	0	0	0	0	0	0	0	0	0	0	0	0	1,137	0	1,137
2026	408	0	0	0	0	0	0	0	0	0	0	0	0	0	408	0	408
2027	420	0	0	0	0	0	0	0	0	0	0	0	0	0	420	0	420
2028	433	0	0	0	0	0	0	0	0	0	0	0	0	0	433	0	433
2029	446	0	0	0	0	0	0	0	0	0	0	0	0	0	446	0	446

COLUMN NOTES
COLUMN (2) THROUGH (16) REPRESENT 59.03% OF THE SAME COLUMN NUMBER ON P. 1
(17) SEE SCHEDULE 2, P. 1, COLUMN (11) x .1
(18) COLUMN (16) + COLUMN (17)

CONTRACT TERMINATION CHARGES ILLUSTRATION CALCULATION
TERMINATION CHARGE MITIGATION INCENTIVE MECHANISM

			MONTAUP ELECTRIC		EASTERN EDISON SHARE (59.02%)		
YEAR (1)	BASE CTC (2)	CUMUL BASE CTC (3)	CUMUL BONUS ALLOWED (4)	NOM. ANN INCREMENTAL BONUS REQ'D (5)	NOM. ANN INCREMENTAL BONUS REQ'D (6)	IMPACT ON CTC (7)	ADJUSTED CTC (8)
1998	3.04	3.04	0	0	0	0	3.04
1999	3.04	3.04	0	0	0	0	3.04
2000	3.04	3.04	0	0	0	0	3.04
2001	2.89	3.00	498	647	382	0.0136	2.90
2002	2.58	2.92	1,828	1,844	1,088	0.0384	2.61
2003	2.34	2.83	3,553	2,555	1,508	0.0524	2.30
2004	2.13	2.74	5,517	3,104	1,832	0.0626	2.10
2005	2.00	2.66	7,234	2,897	1,710	0.0574	2.14
2006	1.90	2.59	9,068	3,305	1,951	0.0641	1.97
2007	1.69	2.52	10,592	2,930	1,729	0.0562	1.04
2008	1.70	2.45	12,180	3,261	1,924	0.0616	1.76
2009	1.72	2.40	13,402	2,680	1,582	0.0500	1.77

(2) SEE P. 1, COLUMN (8)
(3) CUMULATIVE AVG. OF PRIOR YEARS COL (8) AND CURRENT YEAR COL (2).
(4) FOR ANY GIVEN YEAR, INTERPOLATED FROM TABLE AS FOLLOWS:
3.04 - COL (3) X VALUE SHOWN IN TABLE BELOW
3.04 - CUM AVG CTC IN TABLE FOR COL (3) REFERENCE
(5) COL (4) CURRENT YEAR COL (4) PRIOR YEAR * MULTIPLIER, WHERE MULTIPLIER USED
TO CALC COL (5) = (1+ATWACC)^n WHERE n = NUMBER OF YEARS FROM 1998 + 1
(6) COLUMN (5) * 59.02%
(7) COLUMN (6) / EST. EECO KWH SALES ON SCHEDULE 1, P. 1, COLUMN (2).
(8) COLUMN (2) + COLUMN (7)

TABLE:
1998 $ NPV CUMULATIVE BONUS

($000)

CUMUL AVERAGE CTC	YEARS: 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
0.00	6,250	11,692	16,312	20,168	23,355	25,943	27,994	29,568	30,711	31,477	31,908	32,042
0.20	6,250	11,692	16,312	20,168	23,355	25,943	27,994	29,568	30,711	31,477	31,908	32,042
0.40	6,250	11,692	16,312	20,168	23,355	25,943	27,994	29,566	30,711	31,477	31,908	32,042
0.60	6,250	11,692	16,312	20,168	23,355	25,943	27,994	29,566	30,711	31,477	31,908	32,042
0.80	6,250	11,692	16,312	20,168	23,355	25,943	27,994	29,566	30,711	31,477	31,908	32,042
1.00	6,250	11,692	16,312	20,168	23,355	25,943	27,994	29,566	30,711	31,477	31,908	32,042
1.20	5,844	10,833	15,252	18,858	21,839	24,258	26,176	27,648	28,717	29,433	29,836	29,962
1.40	5,438	10,174	14,193	17,549	20,322	22,574	24,358	25,728	26,722	27,389	27,764	27,881
1.60	5,033	9,414	13,134	16,239	18,806	20,889	22,541	23,806	24,728	25,345	25,692	25,800
1.80	4,627	8,655	12,075	14,930	17,289	19,205	20,723	21,886	22,734	23,301	23,620	23,720
2.00	4,221	7,896	11,016	13,620	15,772	17,520	18,905	19,966	20,740	21,257	21,548	21,639
2.20	3,400	6,378	8,897	11,001	12,739	14,151	15,269	16,127	16,751	17,169	17,404	17,478
2.40	2,597	4,859	6,779	8,382	9,706	10,781	11,634	12,287	12,763	13,081	13,260	13,316
2.60	1,788	3,341	4,660	5,762	6,673	7,412	7,998	8,447	8,775	8,993	9,117	9,155
2.80	974	1,822	2,542	3,143	3,640	4,043	4,363	4,608	4,786	4,906	4,973	4,994
3.00	162	304	424	524	607	674	727	768	798	810	829	832
3.20	(649)	(1,215)	(1,695)	(2,095)	(2,427)	(2,695)	(2,908)	(3,072)	(3,191)	(3,270)	(3,315)	(3,329)

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE (1)	LOCATION (2)	YEAR(S) PLACED IN SERVICE (3)	ENERGY SOURCE (4)	NET CAPABILITY MW (5)	$ IN 000 1995 (6)	$ IN 000 1997 (7)	APPLICABLE ANNUAL DEPRECIATION FOR 1998 AND BEYOND (8)
FOSSIL FUEL UNITS							
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032	23,716	2,158
CANAL 2	SANDWICH, MA	1976	OIL	233 0	41,041	35,207	2,917
WYMAN 4	YARMOUTH, ME	1978	OIL	12.2	2,030	1,806	112
NEWPORT OWNED GEN	JAMESTOWN/ PORTSMOUTH, RI/ YARMOUTH, ME	1961 1978 1978	DIESEL DIESEL OIL	8 8 8.3 4.1	1,803	1,499	1,064 Diesels 435 Wyman 152
NUCLEAR UNITS							
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705	160,949	4,878
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45.9	137,749	128,279	4,735
VERMONT YANKEE	BRATTLEBORO, VT	1972	NUCLEAR	12.0	3,786 (a)	3,092	347
MAINE YANKEE	BRUNSWICK, ME	1972	NUCLEAR	31 6	7,439 (a)	6,105	667
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604	604	
	- NET INVESTMENT IN SOMERSET UNIT 5				5,860	6,449	(b)
	- LAND IN PORTSMOUTH, RI				216	216	
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610	2,610	
SETTLEMENT ADJUSTMENT					(500)	(500)	
			TOTAL	542.6	401,375	370,032	15,966

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997).

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF DECEMBER 31, 1995 (1)	DECEMBER 31, 1997 (2)	APPLICABLE AMORTIZATION FOR 1998 AND BEYOND (3)	BASIS FOR DEFERRAL (4)
FAS 109 - ASSET	39,916	37,466	1,225	FERC RATEMAKING POLICY
- LIABILITY	(14,583)	(8,717)	(2,933)	FERC RATEMAKING POLICY
FAS 106 DEFERRAL	1,313	538	387 (a)	FERC RATEMAKING POLICY
NET PENSION LIABILITY / (ASSET) (c)	(485)	(415)	(35)	FAS 87
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607	FERC RATEMAKING POLICY
UNAMORTIZATION ITC	(12,523)	(11,367)	(578)	FERC RATEMAKING POLICY
DREDGING	424	173	125 (b)	FERC RATEMAKING POLICY
TOTAL REG. ASSETS	27,941	28,343	(202)	

(a) REMAINING AMORTIZATION SCHEDULE: 387 IN 1998, 151 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.
(c) Represents the net difference between Montaup's allocated market value in excess of pension benefit obligation and EUASC's (Montaup share of 20.6%) pension benefit obligation in excess of its allocated market value (all as of 12/31/95). In conjunction with inclusion of this regulatory liability, $314,000 ($3,764,000 + 12 years of transition) will be transferred from Montaup's market value and to EUASC's market value annually. This transfer within the Eastern Utilities Associates Employees' Retirement Plan will continue for twelve years following retail access date. Future events such as divesture, filing of retail rate cases, etc, may result in disputes in the amount appropriately included here as a net regulatory credit. The parties agree that such disputes, prior to submission to the FERC for resolution, and, to the extent possible, shall be addressed by good faith efforts to achieve a consensual resolution. Any adjustments necessary to this regulatory liability shall be reflected in the Variable Component of the Contract Termination Charge.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95	9,091
AMORTIZATION AMOUNT (1996 & BEYOND)	534
DISCOUNT RATE	7.25%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
1999	669	509	1,178	6,686
2000	669	460	1,129	6,017
2001	669	412	1,081	5,349
2002	669	364	1,032	4,680
2003	669	315	984	4,011
2004	669	267	935	3,343
2005	669	218	887	2,674
2006	669	170	838	2,006
2007	669	121	790	1,337
2008	669	73	741	669
2009	669	24	693	(0)

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25%
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

(1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	0	0	0	0	0
2002	0	0	0	0	0
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	0	0	0	0
2007	0	0	0	0	0
2008	0	0	0	0	0
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

(1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
1999	621	328	3,102	318	711	2,306	7,386
2000	639	339	3,058	407	713	1,206	6,362
2001	658	349	2,972	408	716	58	5,161
2002	679	359	2,906	409	718	60	5,131
2003	699	370	2,823	456	803	63	5,214
2004	721	382	2,742	457	983	65	5,350
2005	743	394	2,681	585	986	68	5,457
2006	766	405	2,587	587	990	70	5,405
2007	770	409	2,013	578	967	52	4,789
2008	759	406	0	546	510	0	2,221
2009	782	418	0	546	0	0	1,746
2010	806	431	0	710	0	0	1,947
2011	830	444	0	710	0	0	1,984
2012	855	457	0	177	0	0	1,489
2013	880	471	0	0	0	0	1,351
2014	907	485	0	0	0	0	1,392
2015	934	499	0	0	0	0	1,433
2016	962	514	0	0	0	0	1,476
2017	991	530	0	0	0	0	1,521
2018	1,021	546	0	0	0	0	1,567
2019	1,051	562	0	0	0	0	1,613
2020	1,083	579	0	0	0	0	1,662
2021	1,115	596	0	0	0	0	1,711
2022	1,149	614	0	0	0	0	1,763
2023	1,183	633	0	0	0	0	1,816
2024	1,219	652	0	0	0	0	1,871
2025	1,255	671	0	0	0	0	1,926
2026	0	691	0	0	0	0	691
2027	0	712	0	0	0	0	712
2028	0	733	0	0	0	0	733
2029	0	755	0	0	0	0	755

Purchase Power Total $000

	Pidgeon	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	GMP	BSH	OSP @ 9.7% ROE	Total
1998	36,042	25,977	3,932	330	3,562	25,448	27,471	12,513	528	10,662	150	550	(1,206)	145,955
1999	35,710	27,161	3,876	339	3,588	25,638	27,005	12,519	528	10,770	0	0	(1,146)	146,080
2000	36,174	27,040	4,023	347	3,612	24,978	27,541	12,632	531	10,098	0	0	(1,089)	145,885
2001	36,184	28,548	4,079	361	3,710	25,995	27,914	6,063	533	6,935	0	0	(1,034)	139,288
2002	35,333	21,448	4,137	376	3,818	27,847	27,097	8,380	536	3,731	0	0	(983)	129,720
2003	35,763	0	4,196	391	3,935	25,332	29,839	8,970	539	3,612	0	0	(934)	109,645
2004	34,910	0	4,261	406	4,057	25,953	27,792	7,200	541	3,508	0	0	(887)	107,831
2005	35,889	0	4,327	423	4,192	26,533	27,430	7,907	544	3,397	0	0	(842)	109,860
2006	34,488	0	4,395	440	4,335	26,001	26,508	8,179	547	3,225	0	0	(800)	109,318
2007	36,141	0	4,468	457	4,485	26,907	26,363	8,815	550	3,188	0	0	(760)	112,512
2008	33,952	0	4,540	476	4,643	30,870	27,976	8,937	553	2,997	0	0	(722)	114,272
2009	36,999	0	4,618	495	4,805	27,074	32,581	9,404	557	2,809	0	0	(686)	118,734
2010	34,533	0	4,698	514	4,980	26,388	29,600	9,479	560	2,873	0	0	(652)	114,920
2011	40,427	0	4,779	535	5,146	0	27,329	10,500	563	2,740	0	0	(303)	91,776
2012	19,360	0	4,865	556	5,331	0	0	10,270	567	2,659	0	0	0	41,608
2013	0	0	4,955	579	5,519	0	0	10,413	571	2,581	0	0	0	24,618
2014	0	0	5,049	602	5,717	0	0	10,841	575	2,505	0	0	0	25,289
2015	0	0	5,146	626	0	0	0	11,453	578	2,432	0	0	0	20,235
2016	0	0	5,247	651	0	0	0	11,586	582	2,360	0	0	0	20,426
2017	0	0	0	0	0	0	0	12,384	586	1,986	0	0	0	14,956
2018	0	0	0	0	0	0	0	12,095	591	1,927	0	0	0	14,613
2019	0	0	0	0	0	0	0	12,512	0	1,869	0	0	0	14,381
2020	0	0	0	0	0	0	0	12,769	0	1,584	0	0	0	14,353
2021	0	0	0	0	0	0	0	13,455	0	0	0	0	0	13,455
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
1999	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	324,157	2,710,592
2000	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	283,092	2,740,313
2001	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	134,017	2,520,452
2002	553,418	441,228	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	2,310,145
2003	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2004	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2005	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2006	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2007	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2008	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2009	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2010	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2011	482,632	0	36,979	10,234	17,420	0	541,959	194,911	5,453	0	1,289,508
2012	184,473	0	36,979	10,234	17,420	0	0	194,911	5,453	0	449,470
2013	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2014	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2015	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2016	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2017	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2018	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2019	0	0	0	0	0	0	0	194,911	0	0	194,911
2020	0	0	0	0	0	0	0	194,911	0	0	194,911
2021	0	0	0	0	0	0	0	194,911	0	0	194,911
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
1999	1,663	1,234	1,555	4,452
2000	0	815	1,555	2,370
2001	0	0	1,555	1,555
2002	0	0	1,555	1,555
2003	0	0	1,555	1,555
2004	0	0	1,555	1,555
2005	0	0	1,555	1,555
2006	0	0	1,555	1,555
2007	0	0	1,555	1,555
2008	0	0	1,555	1,555
2009	0	0	1,555	1,555
2010	0	0	1,555	1,555
2011	0	0	1,555	1,555
2012	0	0	1,555	1,555
2013	0	0	1,555	1,555
2014	0	0	1,555	1,555
2015	0	0	1,555	1,555
2016	0	0	1,555	1,555
2017	0	0	1,555	1,555
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

(1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YNK (6)	VERMONT YNK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
1999	292	138	507	91	214	55	1,297
2000	286	138	488	91	214	55	1,272
2001	280	138	470	91	214	55	1,248
2002	275	138	452	91	214	55	1,225
2003	269	138	435	91	238	61	1,232
2004	264	138	418	91	238	61	1,210
2005	259	138	402	91	238	61	1,189
2006	254	138	386	91	238	61	1,168
2007	249	138	371	91	238	61	1,148
2008	245	138	357	91	238	61	1,130
2009	240	138	443	91	0	61	973

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	30,204	23,439	1,226	54,869	0	54,869
1999	28,075	30,534	1,178	59,787	0	59,787
2000	25,442	36,878	1,129	63,450	0	63,450
2001	22,673	34,169	1,081	57,923	0	57,923
2002	20,006	34,169	1,032	55,207	0	55,207
2003	17,338	34,169	984	52,491	0	52,491
2004	14,671	34,169	935	49,776	0	49,776
2005	12,004	34,169	887	47,060	0	47,060
2006	9,336	34,169	838	44,344	0	44,344
2007	6,669	34,169	790	41,628	0	41,628
2008	4,001	34,169	741	38,912	0	38,912
2009	1,334	34,169	693	36,196	0	36,196

COLUMN NOTES:
(2) See Schedule 1, p. 15, Column (8).
(3) p. 1 Column (7) / .5902 - p. 16 Column (16) - p. 13 Column (2) - p. 13 Column (4) - p. 13 Column (6) - p. 3 Column (17)/ .5902.
(4) See p. 6a, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based on results of actual market valuation.
(7) Columns (5) + (6)

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENT
$ IN 000

YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BOOK BASIS BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	TAX BASIS BALANCE GENERATION RELATED REG. ASSETS (6)	TOTAL TAX BASIS (7)	EXCESS BOOK OVER TAX (8)	DEFERRED TAXES (9)
1997	370,032	28,343	398,375	67,923	0	67,923	330,452	129,620
1998	348,261	26,675	374,936	63,927	0	63,927	311,009	121,993
1999	319,899	24,503	344,402	58,721	0	58,721	285,681	112,059
2000	285,645	21,879	307,524	52,433	0	52,433	255,091	100,059
2001	253,906	19,448	273,355	46,607	0	46,607	226,748	88,942
2002	222,168	17,017	239,185	40,781	0	40,781	198,404	77,824
2003	190,430	14,586	205,016	34,955	0	34,955	170,061	66,706
2004	158,692	12,155	170,847	29,129	0	29,129	141,717	55,589
2005	126,953	9,724	136,677	23,304	0	23,304	113,374	44,471
2006	95,215	7,293	102,508	17,478	0	17,478	85,030	33,353
2007	63,477	4,862	68,339	11,652	0	11,652	56,687	22,235
2008	31,738	2,431	34,169	5,826	0	5,826	28,343	11,118
2009	(0)	(0)	(0)	(0)	0	(0)	(0)	(0)

COLUMN NOTES:
(2) SEE SCHEDULE 1, P. 5 COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, P. 6 COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)	SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,375	129,620	268,755				
1998	374,936	121,993	252,943	260,849	28,993	1,211	30,204
1999	344,402	112,059	232,344	242,643	26,970	1,106	28,075
2000	307,524	100,059	207,465	219,904	24,442	1,000	25,442
2001	273,355	88,942	184,413	195,939	21,778	895	22,673
2002	239,185	77,824	161,361	172,887	19,216	790	20,006
2003	205,016	66,706	138,310	149,835	16,654	684	17,338
2004	170,847	55,589	115,258	126,784	14,092	579	14,671
2005	136,677	44,471	92,206	103,732	11,530	474	12,004
2006	102,508	33,353	69,155	80,681	8,968	369	9,336
2007	68,339	22,235	46,103	57,629	6,405	263	6,669
2008	34,169	11,118	23,052	34,577	3,843	158	4,001
2009	(0)	(0)	(0)	11,526	1,281	53	1,334

EECO 12/31/95

CAPITAL STRUCTURE			ATWACC	BTWACC
COMMON	48.45%	8.92%	4.32%	7.11%
PFD	5.95%	9.83%	0.58%	0.96%
LTD	45.60%	6.67%	3.04%	3.04%
	100.00%		7.95%	11.115%
TAX RATE				39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, P 14 COLUMN (4).
(3) SEE SCHEDULE 1, P 14 COLUMN (9).
(4) COLUMN (2) - COLUMN (3)
(5) COLUMN (4) PRIOR YEAR+COLUMN (4)/2.
(6) COLUMN (5) x TOTAL RATE OF RETURN
(7)AVERAGE UNAMORT ITC (ASSUMING 12 YR S/L AMORT OF P 6, COLUMN (2)).
(8) COLUMN (6) + COLUMN (7).

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
EASTERN EDISON COMPANY SHARE (100%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOMMISS COSTS (2)	TOTAL OBLIGATION (3)	POWER CONTRACTS ASSUMED MARKET VALUE (4)	POWER CONTRACTS NET EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS NET EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN UNITS (11)	PMTS IN LIEU OF PROP TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES COSTS OR NET RECOVERIES FROM CLAIMS (14)	PMT FOR NUKE UNITS REM AFTER MKT VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)
1998	8,011	145,955	68,872	77,083	0	(4,854)	0	(4,854)	473	1,322	0	0	0	0	82,035
1999	7,386	146,086	71,108	74,920	0	(4,452)	0	(4,452)	451	1,297	0	0	0	0	79,440
2000	8,362	145,065	72,828	73,257	0	(2,370)	0	(2,370)	430	1,272	0	0	0	0	78,351
2001	5,161	139,286	85,308	73,982	0	(1,555)	0	(1,555)	410	1,248	0	0	0	0	79,246
2002	5,131	129,720	66,390	63,330	0	(1,555)	0	(1,555)	373	1,225	0	0	0	0	68,684
2003	5,214	109,646	53,329	56,316	0	(1,555)	0	(1,555)	348	1,232	0	0	0	0	61,853
2004	5,350	107,831	57,331	50,500	0	(1,555)	0	(1,555)	319	1,210	0	0	0	0	55,024
2005	5,457	108,800	58,820	52,980	0	(1,555)	0	(1,555)	291	1,188	0	0	0	0	56,362
2006	5,405	109,318	60,784	48,534	0	(1,555)	0	(1,555)	264	1,166	0	0	0	0	53,018
2007	4,780	112,512	60,369	52,143	0	(1,555)	0	(1,555)	237	1,148	0	0	0	0	56,762
2008	2,271	114,222	65,139	49,083	0	(1,555)	0	(1,555)	209	1,130	0	0	0	0	51,086
2009	1,740	118,724	44,362	54,372	0	(1,555)	0	(1,555)	182	973	0	0	0	0	55,710
2010	1,067	114,920	69,338	45,582	0	(1,555)	0	(1,555)	155	0	0	0	0	0	46,124
2011	1,084	91,776	49,040	42,736	0	(1,555)	0	(1,555)	37	0	0	0	0	0	43,283
2012	1,408	43,000	17,737	25,871	0	(1,555)	0	(1,555)	0	0	0	0	0	0	25,003
2013	1,351	24,818	10,724	13,094	0	(1,555)	0	(1,555)	0	0	0	0	0	0	13,690
2014	1,392	25,288	10,862	14,327	0	(1,555)	0	(1,555)	0	0	0	0	0	0	14,164
2015	1,433	20,235	10,492	9,743	0	(1,555)	0	(1,555)	0	0	0	0	0	0	9,621
2016	1,476	28,426	10,879	9,547	0	(1,555)	0	(1,555)	0	0	0	0	0	0	9,469
2017	1,521	14,958	9,131	5,825	0	0	0	0	0	0	0	0	0	0	7,346
2018	1,567	14,813	9,319	5,294	0	0	0	0	0	0	0	0	0	0	6,861
2019	1,613	14,381	9,066	5,315	0	0	0	0	0	0	0	0	0	0	6,928
2020	1,667	14,353	8,860	5,493	0	0	0	0	0	0	0	0	0	0	7,166
2021	1,711	13,455	8,996	4,458	0	0	0	0	0	0	0	0	0	0	6,170
2022	1,763	0	0	0	0	0	0	0	0	0	0	0	0	0	1,763
2023	1,816	0	0	0	0	0	0	0	0	0	0	0	0	0	1,816
2024	1,871	0	0	0	0	0	0	0	0	0	0	0	0	0	1,871
2025	1,926	0	0	0	0	0	0	0	0	0	0	0	0	0	1,926
2026	691	0	0	0	0	0	0	0	0	0	0	0	0	0	691
2027	712	0	0	0	0	0	0	0	0	0	0	0	0	0	712
2028	733	0	0	0	0	0	0	0	0	0	0	0	0	0	733
2029	755	0	0	0	0	0	0	0	0	0	0	0	0	0	755

Column Notes
(2) Schedule 1, p. 8 Column (8)
(3) Schedule 1, p. 9
(5) Column (3) - Column (4)
(7) See Schedule 1, p. 11 Column (5)
(9) Column (7) - Column (8)
(11) Schedule 1, p. 12 Column (8)

RESIDUAL VALUE CALCALATION

RI
MITIGATION

APPENDIX 1, 1.1.4. (c) :		RVC Wkp. page	($000) 12/31/98	CTC (1) 12/31/98	POST 95 ADDITIONS	PROCEED ABOVE BOOK
Sale Proceeds			75,700	33,100	6,300	36,300
(i) Less: Employee Severance			(15,000)			
(ii) Less: Lost Revenue			(17,300)			
(iii) Less: Post 95 Additions			(6,300)			
(iv) Less Transaction And Financing Costs			(8,100)			
Less: RI Return Differential			(4,800)			
Residual Value Credit	RVC		24,200			
(iv) Less: Accum Dfd Taxes and Prepaid Taxes	(a)		(20,000)			
RVC BASE FOR ROR INTEREST CALC			**4,200**			

(a)

		Bk Basis	Tx Basis	Def Tax @ 39.225%	Cur. Tax @ 39.225%	
Plant sold @ 12/31/98	(1)	33,100	18,400	5,766		
Plant Additions	(2)	6,300	6,300	0		
		39,400	24,700	5,766		
Accumulated Deferred Taxes					5,766	
Proceeds Impact		75,700				
Greater than book value		36,300	0		14,239	
Current Taxes					20,005	
					USE	**20,000**

(1) 1997 CTC Canal book basis ($35.2m) and tax basis ($19.6m) reduced by 1998 amortization rate of 5.884% rounded to nearest $100K to derrive 1998 balances.

(2) For demonstration purposes book basis and tax basis assumed to be the same on net plant additions.

FOR ILLUSTRATIVE PURPOSES ONLY

EXHIBIT MEC-_-NEC (DTS-4-NEC)

Exhibit MEC-13-NEC (DTS-4-NEC)

RESIDUAL VALUE CALCALATION

RI
MITIGATION

APPENDIX 1, 1.1.4, (c) :		RVC Wkp. page	($000) 12/31/98	CTC (1) 12/31/98	POST 95 ADDITIONS	PROCEEDS ABOVE BOOK
Sale Proceeds			75,700	33,100	6,300	36,300
(i) Less: Employee Severance			(15,000)			
(ii) Less: Lost Revenue			(17,300)			
(iii) Less: Post 95 Additions			(6,300)			
(iv) Less Transaction And Financing Costs			(8,100)			
Less: RI Return Differential			(4,800)			
Residual Value Credit	RVC		24,200			
(iv) Less: Accum Dfd Taxes and Prepaid Taxes	(a)		(20,000)			
RVC BASE FOR ROR INTEREST CALC			4,200			

(a)

		Bk Basis	Tx Basis	Def Tax @ 39.225%	Cur. Tax @ 39.225%	
Plant sold @ 12/31/98	(1)	33,100	18,400	5,766		
Plant Additions	(2)	6,300	6,300	0		
		39,400	24,700	5,766		
Accumulated Deferred Taxes					5,766	
Proceeds Impact		75,700				
Greater than book value		36,300	0		14,239	
Current Taxes					20,005	
					USE	20,000

(1) 1997 CTC Canal book basis ($35.2m) and tax basis ($19.6m) reduced by 1998 amortization rate of 5.884% rounded to nearest $100K to derrive 1998 balances.

(2) For demonstration purposes book basis and tax basis assumed to be the same on net plant additions.

MITRVC.WK4

RESIDUAL VALUE CALCALATION

MA.
MITIGATION

APPENDIX 1, 1.1.4. (c) :		RVC Wkp. page	($000) 12/31/98	CTC (1) 12/31/98	POST 95 ADDITIONS	PROCEED ABOVE BOOK
Sale Proceeds			75,700	33,100	6,300	36,300
(i) Less: Employee Severance			(15,000)			
(ii) Less: Lost Revenue			(17,300)			
(iii) Less: Post 95 Additions			(6,300)			
(iv) Less Transaction And Financing Costs			(8,100)			
Less: RI Return Differential			0			
Residual Value Credit	RVC		29,000			
(iv) Less: Accum Dfd Taxes and Prepaid Taxes	(a)		(20,000)			
RVC BASE FOR ROR INTEREST CALC			**9,000**			

(a)

		Bk Basis	Tx Basis	Def Tax @ 39.225%	Cur. Tax @ 39.225%	
Plant sold @ 12/31/98	(1)	33,100	18,400	5,766		
Plant Additions	(2)	6,300	6,300	0		
		39,400	24,700	5,766		
Accumulated Deferred Taxes					5,766	
Proceeds Impact		75,700				
Greater than book value		36,300	0		14,239	
Current Taxes					20,005	
					USE	20,000

(1) 1997 CTC Canal book basis ($35.2m) and tax basis ($19.6m) reduced by 1998 amortization rate of 5.884% rounded to nearest $100K to derrive 1998 balances.

(2) For demonstration purposes book basis and tax basis assumed to be the same on net plant additions.

Exhibit MEC-14-EEC
(DTS-4-EEC)

FOR ILLUSTRATIVE PURPOSES ONLY

RVC - MONTAUP ELECTRIC COMPANY
BLACKSTONE'S SHARE

Calculation of R.I. Residual Value Credit - CANAL II

			1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
RVC Mitigation Amount	24,200													
Accum. Deferred & PrepaidTaxes	(20,000)													
ROR Interest Basis	4,200													
Beginning RVC Balance				24,200	22,000	19,800	17,600	15,400	13,200	11,000	8,800	6,600	4,400	2,200
Required Depreciation / Amortization				2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
Ending RVC Balance				22,000	19,800	17,600	15,400	13,200	11,000	8,800	6,600	4,400	2,200	0
Beginning Accum Dfd Tax & Prepaid Balance				(20,000)	(18,182)	(16,364)	(14,545)	(12,727)	(10,909)	(9,091)	(7,273)	(5,455)	(3,636)	(1,818)
Tax Provision				(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)
Ending Accum Dfd & Prepaid Tax Balance				(18,182)	(16,364)	(14,545)	(12,727)	(10,909)	(9,091)	(7,273)	(5,455)	(3,636)	(1,818)	(0)
Beginning RVC (Net of Dfd Taxes)				4,200	3,818	3,436	3,055	2,673	2,291	1,909	1,527	1,145	764	382
Ending RVC (Net of Dfd Taxes)				3,818	3,436	3,055	2,673	2,291	1,909	1,527	1,145	764	382	(0)
Average RVC Interest Basis				4,009	3,627	3,245	2,864	2,482	2,100	1,718	1,336	955	573	191
Return @ BTWACC (wkp. p. 11)	13.092%			525	475	425	375	325	275	225	175	125	75	25
	NPV @ ATWACC													
Return of RVC				2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
Return on RVC				525	475	425	375	325	275	225	175	125	75	25
	9.14%													
Total Return	17,023			2,725	2,675	2,625	2,575	2,525	2,475	2,425	2,375	2,325	2,275	2,225
Levelized Residual Value Credit	17,023	(Ex.6 p.12)		2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518
BVE Share @ 29.13%		(Ex.6 p.2)		**733**	**733**	**733**	**733**	**733**	**733**	**733**	**733**	**733**	**733**	**733**

Exhibit MEC-15-BV (DTS-5-BVE)

FOR ILLUSTRATIVE PURPOSES ONLY

EXHIBIT MEC-_-NEC (DTS-5-NEC)

RVC -MONTAUP ELECTRIC COMPANY
NEWPORT'S SHARE

Calculation of R.I. Residual Value Credit -CANAL II

			1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
RVC Mitigation Amount	24,200													
Accum. Deferred & PrepaidTaxes	(20,000)													
ROR Interest Basis	4,200													
Beginning RVC Balance				24,200	22,000	19,800	17,600	15,400	13,200	11,000	8,800	6,600	4,400	2,200
Required Depreciation / Amortization				2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
Ending RVC Balance				22,000	19,800	17,600	15,400	13,200	11,000	8,800	6,600	4,400	2,200	0
Beginning Accum Dfd Tax & Prepaid Balance				(20,000)	(18,182)	(16,364)	(14,545)	(12,727)	(10,909)	(9,091)	(7,273)	(5,455)	(3,636)	(1,818)
Tax Provision				(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)
Ending Accum Dfd & Prepaid Tax Balance				(18,182)	(16,364)	(14,545)	(12,727)	(10,909)	(9,091)	(7,273)	(5,455)	(3,636)	(1,818)	(0)
Beginning RVC (Net of Dfd Taxes)				4,200	3,818	3,436	3,055	2,673	2,291	1,909	1,527	1,145	764	382
Ending RVC (Net of Dfd Taxes)				3,818	3,436	3,055	2,673	2,291	1,909	1,527	1,145	764	382	(0)
Average RVC Interest Basis				4,009	3,627	3,245	2,864	2,482	2,100	1,718	1,336	955	573	191
Return @ BTWACC (wkp, p. 11)	13.092%			525	475	425	375	325	275	225	175	125	75	25
	NPV @ ATWACC													
Return of RVC				2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
Return on RVC				525	475	425	375	325	275	225	175	125	75	25
	9.14%													
Total Return	17,023			2,725	2,675	2,625	2,575	2,525	2,475	2,425	2,375	2,325	2,275	2,225
Levelized Residual Value Credit	17,023	(EX.6 p.12		2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518
NEC Share @ 11.85%		(Ex.6 p.2)		**298**	**298**	**298**	**298**	**298**	**298**	**298**	**298**	**298**	**298**	**298**

MITRVC.WK4

Exhibit MEC-16-NEC
(DTS-5-NEC)

RVC - MONTAUP ELECTRIC COMPANY
EASTERN'S SHARE

Calculation of MA. Residual Value Credit -CANAL II

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
RVC Mitigation Amount	29,000												
Accum. Deferred & PrepaidTaxes	(20,000)												
ROR Interest Basis	9,000												
Beginning RVC Balance			29,000	26,364	23,727	21,091	18,455	15,818	13,182	10,545	7,909	5,273	2,636
Required Depreciation / Amortization			2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636
Ending RVC Balance			26,364	23,727	21,091	18,455	15,818	13,182	10,545	7,909	5,273	2,636	0
Beginning Accum Dfd Tax & Prepaid Balance			(20,000)	(18,182)	(16,364)	(14,545)	(12,727)	(10,909)	(9,091)	(7,273)	(5,455)	(3,636)	(1,818)
Tax Provision			(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)
Ending Accum Dfd & Prepaid Tax Balance			(18,182)	(16,364)	(14,545)	(12,727)	(10,909)	(9,091)	(7,273)	(5,455)	(3,636)	(1,818)	(0)
Beginning RVC (Net of Dfd Taxes)			9,000	8,182	7,364	6,545	5,727	4,909	4,091	3,273	2,455	1,636	818
Ending RVC (Net of Dfd Taxes)			8,182	7,364	6,545	5,727	4,909	4,091	3,273	2,455	1,636	818	0
Average RVC Interest Basis			8,591	7,773	6,955	6,136	5,318	4,500	3,682	2,864	2,045	1,227	409
Return @ BTWACC (Ex.3 p.15)	11.115%		955	864	773	682	591	500	409	318	227	136	45
	NPV @ ATWACC												
Return of RVC			2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636
Return on RVC	7.95%		955	864	773	682	591	500	409	318	227	136	45
Total Return	22,938		3,591	3,500	3,409	3,318	3,227	3,137	3,046	2,955	2,864	2,773	2,682
Levelized Residual Value Credit	22,938 (Ex.6 p.13)		3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205
EEC Share @ 59.02%	(Ex.6 p.2)		**1,892**	**1,892**	**1,892**	**1,892**	**1,892**	**1,892**	**1,892**	**1,892**	**1,892**	**1,892**	**1,892**

Exhibit MEC-17-EE(
(DTS-5-EEC)

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO BLACKSTONE VALLEY ELECTRIC

YEAR	EST. BVE MWH SALES	SHARE OF FIXED COMPONENT		SHARE OF VAR. COMPONENT		SHARE OF TOT. TERM CHARGE	BASE CONTRACT TERM CHARGE
		$ IN 000	CENTS/KWH	$ IN 000	CENTS/KWH	$ IN 000	CENTS/KWH
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1998	1,293,212	14,900	1.15	23,897	1.85	38,796	3.00
1999	1,309,137	15,351	1.17	23,190	1.77	38,541	2.94
2000	1,329,905	16,165	1.22	22,998	1.73	39,164	2.94
2001	1,346,024	12,327	0.92	23,084	1.72	35,411	2.63
2002	1,360,074	14,337	1.05	19,955	1.47	34,292	2.52
2003	1,377,851	15,366	1.12	17,931	1.30	33,296	2.42
2004	1,399,848	16,162	1.15	16,261	1.16	32,423	2.32
2005	1,423,866	14,609	1.03	17,001	1.19	31,610	2.22
2006	1,452,574	15,234	1.05	15,677	1.08	30,911	2.13
2007	1,471,219	13,469	0.92	16,535	1.12	30,004	2.04
2008	1,493,432	14,308	0.96	14,882	1.00	29,189	1.95
2009	1,512,696	12,103	0.80	16,231	1.07	28,334	1.87
2010	1,534,838	0	0.00	13,437	0.88	13,437	0.88
2011	1,550,396	0	0.00	12,585	0.81	12,585	0.81
2012	1,566,958	0	0.00	7,517	0.48	7,517	0.48
2013	1,597,666	0	0.00	3,988	0.25	3,988	0.25
2014	1,624,096	0	0.00	4,126	0.25	4,126	0.25
2015	1,644,785	0	0.00	2,802	0.17	2,802	0.17
2016	1,671,116	0	0.00	2,758	0.17	2,758	0.17
2017	1,693,977	0	0.00	2,140	0.13	2,140	0.13
2018	1,713,946	0	0.00	1,999	0.12	1,999	0.12
2019	1,739,097	0	0.00	2,018	0.12	2,018	0.12
2020	1,762,428	0	0.00	2,084	0.12	2,084	0.12
2021	1,787,024	0	0.00	1,797	0.10	1,797	0.10
2022	1,811,988	0	0.00	514	0.03	514	0.03
2023	1,837,328	0	0.00	529	0.03	529	0.03
2024	1,863,048	0	0.00	545	0.03	545	0.03
2025	1,889,155	0	0.00	561	0.03	561	0.03
2026	1,915,656	0	0.00	201	0.01	201	0.01
2027	2,011,439	0	0.00	207	0.01	207	0.01
2028	2,112,011	0	0.00	214	0.01	214	0.01
2029	2,217,611	0	0.00	220	0.01	220	0.01

Exhibit MEC-18-BVE
(DTS-6-BVE)

SUMMARY OF CONTRACT TERMINATION CHARGES
BLACKSTONE VALLEY ELECTRIC COMPANY SHARE (29.13%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (6)	ADJ. FOR RESIDUAL VALUE CREDIT (7)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (8)
1998	9,035	5,507	357	14,900	0	14,900
1999	8,517	7,225	343	16,084	(733)	15,351
2000	7,876	8,694	329	16,899	(733)	16,165
2001	7,304	5,441	315	13,060	(733)	12,327
2002	6,758	8,012	301	15,070	(733)	14,337
2003	6,047	9,766	287	16,099	(733)	15,366
2004	5,205	11,418	272	16,895	(733)	16,162
2005	4,325	10,759	258	15,343	(733)	14,609
2006	3,411	12,312	244	15,967	(733)	15,234
2007	2,469	11,504	230	14,203	(733)	13,469
2008	1,487	13,338	216	15,041	(733)	14,308
2009	481	12,154	202	12,836	(733)	12,103

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)		AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	31,016	18,907	0	1,226	51,148	0	51,148
1999	29,236	24,802	0	1,178	55,216	(2,518)	52,698
2000	27,038	29,844	0	1,129	58,011	(2,518)	55,493
2001	25,074	18,679	0	1,081	44,834	(2,518)	42,316
2002	23,200	27,503	0	1,032	51,735	(2,518)	49,217
2003	20,758	33,525	0	984	55,267	(2,518)	52,749
2004	17,868	39,196	0	935	57,999	(2,518)	55,481
2005	14,848	36,936	0	887	52,671	(2,518)	50,153
2006	11,711	42,265	0	838	54,814	(2,518)	52,296
2007	8,475	39,490	0	790	48,756	(2,518)	46,238
2008	5,105	45,788	0	741	51,635	(2,518)	49,117
2009	1,650	41,723	0	693	44,066	(2,518)	41,548

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO NEWPORT ELECTRIC COMPANY

YEAR (1)	EST. NEC MWH SALES (2)	SHARE OF FIXED COMPONENT $ IN 000 (3)	SHARE OF FIXED COMPONENT CENTS/KWH (4)	SHARE OF VAR. COMPONENT $ IN 000 (5)	SHARE OF VAR. COMPONENT CENTS/KWH (6)	SHARE OF TOT. TERM CHARGE $ IN 000 (7)	BASE CONTRACT TERM CHARGE CENTS/KWH (8)
1998	530,586	6,196	1.17	9,721	1.83	15,918	3.00
1999	536,555	6,365	1.19	9,434	1.76	15,798	2.94
2000	544,130	6,670	1.23	9,356	1.72	16,026	2.95
2001	549,613	5,052	0.92	9,391	1.71	14,442	2.63
2002	555,606	5,858	1.05	8,118	1.46	13,975	2.52
2003	563,367	6,271	1.11	7,294	1.29	13,565	2.41
2004	571,358	6,554	1.15	6,615	1.16	13,169	2.30
2005	580,288	5,888	1.01	6,916	1.19	12,804	2.21
2006	589,480	6,073	1.03	6,377	1.08	12,450	2.11
2007	596,369	5,330	0.89	6,726	1.13	12,056	2.02
2008	603,135	5,616	0.93	6,054	1.00	11,670	1.93
2009	609,079	4,676	0.77	6,603	1.08	11,279	1.85
2010	616,061	0	0.00	5,466	0.89	5,466	0.89
2011	622,439	0	0.00	5,119	0.82	5,119	0.82
2012	627,545	0	0.00	3,058	0.49	3,058	0.49
2013	636,621	0	0.00	1,622	0.25	1,622	0.25
2014	643,741	0	0.00	1,678	0.26	1,678	0.26
2015	649,276	0	0.00	1,140	0.18	1,140	0.18
2016	654,269	0	0.00	1,122	0.17	1,122	0.17
2017	661,599	0	0.00	870	0.13	870	0.13
2018	667,717	0	0.00	813	0.12	813	0.12
2019	673,767	0	0.00	821	0.12	821	0.12
2020	680,723	0	0.00	848	0.12	848	0.12
2021	687,311	0	0.00	731	0.11	731	0.11
2022	694,002	0	0.00	209	0.03	209	0.03
2023	700,796	0	0.00	215	0.03	215	0.03
2024	707,697	0	0.00	222	0.03	222	0.03
2025	714,705	0	0.00	228	0.03	228	0.03
2026	721,821	0	0.00	82	0.01	82	0.01
2027	757,912	0	0.00	84	0.01	84	0.01
2028	795,808	0	0.00	87	0.01	87	0.01
2029	835,598	0	0.00	89	0.01	89	0.01

SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	3,670	2,381	145	6,196	0	6,196
1999	3,449	3,075	140	6,663	(298)	6,365
2000	3,178	3,656	134	6,968	(298)	6,670
2001	2,938	2,284	128	5,350	(298)	5,052
2002	2,711	3,323	122	6,156	(298)	5,858
2003	2,417	4,036	117	6,569	(298)	6,271
2004	2,071	4,671	111	6,853	(298)	6,554
2005	1,712	4,369	105	6,186	(298)	5,888
2006	1,344	4,928	99	6,372	(298)	6,073
2007	968	4,566	94	5,628	(298)	5,330
2008	580	5,247	88	5,914	(298)	5,616
2009	186	4,706	82	4,974	(298)	4,676

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	30,970	20,094	1,226	52,290	0	52,290
1999	29,101	25,950	1,178	56,229	(2,518)	53,711
2000	26,821	30,854	1,129	58,803	(2,518)	56,285
2001	24,796	19,273	1,081	45,149	(2,518)	42,631
2002	22,878	28,040	1,032	51,950	(2,518)	49,432
2003	20,395	34,059	984	55,437	(2,518)	52,919
2004	17,477	39,416	935	57,828	(2,518)	55,310
2005	14,451	36,865	887	52,203	(2,518)	49,685
2006	11,342	41,588	838	53,768	(2,518)	51,250
2007	8,169	38,536	790	47,494	(2,518)	44,976
2008	4,894	44,274	741	49,909	(2,518)	47,391
2009	1,573	39,711	693	41,977	(2,518)	39,459

Exhibit MEC-20-EEC
(DTS-6-EEC)

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO EASTERN EDISON

YEAR (1)	EST. EECO MWH SALES (2)	SHARE OF FIXED COMPONENT $ IN 000 (3)	SHARE OF FIXED COMPONENT CENTS/KWH (4)	SHARE OF VAR. COMPONENT $ IN 000 (5)	SHARE OF VAR. COMPONENT CENTS/KWH (6)	SHARE OF TOT. TERM CHARGE $ IN 000 (7)	BASE CONTRACT TERM CHARGE CENTS/KWH (8)
1998	2,657,921	32,384	1.22	48,417	1.82	80,801	3.04
1999	2,706,272	33,394	1.23	46,985	1.74	80,379	2.97
2000	2,764,630	35,556	1.29	46,597	1.69	82,153	2.97
2001	2,803,400	32,295	1.15	46,771	1.67	79,066	2.82
2002	2,834,527	30,692	1.08	40,431	1.43	71,123	2.51
2003	2,878,068	29,089	1.01	36,329	1.26	65,418	2.27
2004	2,927,804	27,486	0.94	32,947	1.13	60,433	2.06
2005	2,960,479	25,883	0.87	34,445	1.16	60,328	2.02
2006	3,042,237	24,280	0.80	31,762	1.04	56,042	1.84
2007	3,078,060	22,677	0.74	33,501	1.09	56,178	1.83
2008	3,125,312	21,074	0.67	30,152	0.96	51,226	1.64
2009	3,162,865	19,471	0.62	32,885	1.04	52,356	1.66
2010	3,207,992	0	0.00	27,225	0.85	27,225	0.85
2011	3,230,420	0	0.00	25,498	0.79	25,498	0.79
2012	3,260,202	0	0.00	15,230	0.47	15,230	0.47
2013	3,330,172	0	0.00	8,080	0.24	8,080	0.24
2014	3,385,866	0	0.00	8,360	0.25	8,360	0.25
2015	3,427,278	0	0.00	5,678	0.17	5,678	0.17
2016	3,480,882	0	0.00	5,588	0.16	5,588	0.16
2017	3,524,399	0	0.00	4,336	0.12	4,336	0.12
2018	3,561,432	0	0.00	4,049	0.11	4,049	0.11
2019	3,616,299	0	0.00	4,089	0.11	4,089	0.11
2020	3,661,777	0	0.00	4,223	0.12	4,223	0.12
2021	3,710,922	0	0.00	3,642	0.10	3,642	0.10
2022	3,760,846	0	0.00	1,041	0.03	1,041	0.03
2023	3,811,584	0	0.00	1,072	0.03	1,072	0.03
2024	3,863,089	0	0.00	1,104	0.03	1,104	0.03
2025	3,915,436	0	0.00	1,137	0.03	1,137	0.03
2026	3,968,619	0	0.00	408	0.01	408	0.01
2027	4,167,050	0	0.00	420	0.01	420	0.01
2028	4,375,402	0	0.00	433	0.01	433	0.01
2029	4,594,173	0	0.00	446	0.01	446	0.01

SUMMARY OF CONTRACT TERMINATION CHARGES
EASTERN EDISON COMPANY SHARE (59.02%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	17,826	13,834	724	32,384	0	32,384
1999	16,570	18,021	695	35,286	(1,892)	33,394
2000	15,016	21,765	666	37,448	(1,892)	35,556
2001	13,382	20,167	638	34,186	(1,892)	32,295
2002	11,808	20,167	609	32,583	(1,892)	30,692
2003	10,233	20,167	581	30,980	(1,892)	29,089
2004	8,659	20,167	552	29,378	(1,892)	27,486
2005	7,085	20,167	523	27,775	(1,892)	25,883
2006	5,510	20,167	495	26,172	(1,892)	24,280
2007	3,936	20,167	466	24,569	(1,892)	22,677
2008	2,362	20,167	438	22,966	(1,892)	21,074
2009	787	20,167	409	21,363	(1,892)	19,471

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)		AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	BASE TOTAL FIXED COMPONENT (5)	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	30,204	23,439	0	1,226	54,869	0	54,869
1999	28,075	30,534	0	1,178	59,787	(3,205)	56,581
2000	25,442	36,878	0	1,129	63,450	(3,205)	60,244
2001	22,673	34,169	0	1,081	57,923	(3,205)	54,718
2002	20,006	34,169	0	1,032	55,207	(3,205)	52,002
2003	17,338	34,169	0	984	52,491	(3,205)	49,286
2004	14,671	34,169	0	935	49,776	(3,205)	46,570
2005	12,004	34,169	0	887	47,060	(3,205)	43,854
2006	9,336	34,169	0	838	44,344	(3,205)	41,138
2007	6,669	34,169	0	790	41,628	(3,205)	38,422
2008	4,001	34,169	0	741	38,912	(3,205)	35,707
2009	1,334	34,169	0	693	36,196	(3,205)	32,991

Exhibit MEC-21
(DTS-7)

CANAL II DIVESTITURE PROCEEDS

	Wkp Ref.	($000)
Sales Proceeds from Southern Company		$75,100
Transmission Plant Sale to Comm. Elec.		601
Total Canal II Sales Proceeds		$75,701
	Use	**$75,700**

CANALWKP.WK4

CANAL II DIVESTITURE

Net Post 1995 Additions

	Wkp Ref.	CANAL 2
Net Post 1995 Additions thru 1997	p. 3	$6,046
Capital Improvements Included in $75.1m		511
Additions		6,557
Depreciation Rate - Production Plant		3.53%
Depreciation		231
Depreciated Net Additions		$6,326
USE		$6,300

POST 1995 GENERATION RELATED NET CAPITAL ADDITIONS

THROUGH DECMBER 1997 RECONCILED TO FERC FORM 1

	PROD	CANAL TRANS	GEN	TOTAL
PLANT IN SERVICE				
PLANT IN SERVICE 12/31/95				
PERCENT INCLUDED IN CTC				
GEN RELATED PLANT 12/31/95	68,837	2,230	646	71,713
1996 PLANT ADDITIONS	13,831	0	3	13,834
1996 PLANT RETIREMENTS	(2,341)		(14)	(2,355)
NET ADDITIONS				
GENERATION RELATED	11,490	0	(11)	11,479
GEN RELATED PLANT 12/31/96	80,327	2,230	635	83,192
1997 PLANT ADDITIONS	2,667	147	0	2,814
1997 PLANT RETIREMENTS	(193)	(63)	(2)	(258)
TRANSFERS AND ADJ'S				
NET ADDITIONS				
GENERATION RELATED	2,474	84	(2)	2,556
GEN RELATED PLANT 12/31/97	82,801	2,314	633	85,748
CTC PLANT PER FILING	80,822	2,230	646	83,698
CTC DIFFERENCE FROM ACTUAL	1,979	84	(13)	2,050
ACCUMULATED DEPRECIATION				
12/31/95 BALANCE				
ACCUM. RESERVE BAL. 12/31/95	41,456	1,147	54	42,657
1996 BOOK DEPRECIATION	2,633	54	10	2,697
1996 COST OF REMOVAL	(1,155)			(1,155)
1996 SALVAGE				0
1996 RETIREMENTS	(2,341)		(14)	(2,355)
NET CHANGE IN RESERVE				
CHANGE IN RESERVE	(863)	54	(4)	(813)
ACCUM. RESERVE BAL. 12/31/96	40,593	1,201	50	41,844
1997 BOOK DEPRECIATION	2,879	55	9	2,943
1997 COST OF REMOVAL	(34)			(34)
1997 SALVAGE				0
1997 RETIREMENTS	(192)	(63)	(2)	(257)
CHANGE IN RESERVE	2,653	(8)	7	2,652
ACCUM. RESERVE BAL. 12/31/97	43,246	1,193	57	44,496
ACCUM RES. PER CTC FILING	47,162	1,256	74	48,492
CTC DIFFERENCE FROM ACTUAL	(3,916)	(63)	(17)	(3,996)
12/31/97 GEN REL. NET PLNT	39,555	1,121	576	41,252
12/31/97 CTC PLNT PER FILING	33,660	974	572	35,206
POST '95 GEN REL NET ADD'S	5,895	147	4	6,046

equal to the sale ~~price and other~~ consideration received by Montaup excluding $15 million[9] which purchasers will be required to pay into an account for employee benefits pursuant to Section 1.2.2(f), less

(ii) The revenues lost or gained by Montaup between July 1, 1997 and the Divestiture Date measured by the difference between the revenues excluding revenues attributable to items included in the Contract Termination Charge or in Montaup's transmission rates, that Montaup would have collected under Rate M-14 had it continued to make the sales to Blackstone under Tariff 1 and the revenues, excluding transmission revenues and Contract Termination Charge revenues, that it actually collected from sales to Blackstone's customers during the period, together with a credit for Blackstone's share of the revenue from sales at no less than market prices made by Montaup to third parties during the period. provided, however, the lost revenues so calculated shall not exceed $0.008 per kilowatthour multiplied by the number of

are included in the variable component of the Contract Termination Charge. Montaup reserves its right to revise the variable cost estimates and the amortization of fixed cost components in Schedule 1 to reflect the assignment of obligations to the purchasers, if such revision is necessary to maintain a stable and declining pattern of Contract Termination Charges as offset by the Residual Value Credit.

[9] This figure consists of $11.8 million as shown on Schedule 5 and an estimated $3.2 million for Canal 2 based on Montaup's 25% share of employee costs for Canal Station. The parties agree to use a reasonable actual figure for Canal 2 when available from Canal Electric.

LOST REVENUES
as of 12/31/98

1998 Budgeted kWh Delvered to:	(1)	
Blackstone		1,266,971,853
Newport		543,140,354
Eastern		2,202,459,929
Total kWh		4,012,572,136
Actual year-to-date April average mills per kWh	(2)	$0.0043
Estimated Lost Revenues 12/31/98		$17,254,060
USE		**$17.3 MILLION**

(1) Amounts from 1998 kWh budget based upon Co. Retail Access Date.

(2) Lost revenues deffered on books devided by actual kWh.

RESIDUAL VALUE CREDIT
TRANSACTION and FINANCING COSTS
$(000)

Description	Wkp Ref	Amount
Transaction Costs		
Consultants	(1)	$2,000
Legal and Other	(1)	3,000
Financing Costs	(2)	3,100
Total Transaction and Financing Costs		**$8,100**

(1) Amount will be updated in initial RVC filing, use number indicated as placeholder.

(2) See workpaper page 8 for estimated amount, note that this amount does not include an estimate for the cost of redeeming preferred stock, and will be updated in initial RVC filing.

Wkp page 7a
0

EASTERN EDISON - CAPITALIZATION @ 1997

SECURITIES	RATE	MATURITY	12/31/97 ($000)
First Mortgage and Collateral Trust Bonds:			
	5.875%	5/98	$20,000
	5.750%	7/98	$40,000
	6.350%	9/03	$8,000
	6.875%	5/03	$40,000
	8.000%	5/23	$40,000
Secured Medium Term Notes:			
	7.780%	7/30/02	$35,000
Pollution Control Revenue Bonds:			
	5.875%	8/08	$40,000
Total Debt			$223,000
Preferred Stock:			
	6.625%	9/08	$30,000
Total Debt and Pref. Stk. in Capitalization			$253,000

Wkp page 8

EASTERN EDISON - DEBT PREMIUMS
ASSOCIATED WITH ASSET SALE

SECURITIES	RATE	MATURITY	12/31/98 ($000)	PRICE TO CALL @12/31/98	PREMIUM PAID ($000)
First Mortgage and Collateral Trust Bonds:					
	5.875%	5/98	$0	100.000%	$0
	5.750%	7/98	$0	100.000%	$0
	6.350%	9/03	$8,000	101.815%	$145
	6.875%	5/03	$0	101.822%	$0
	8.000%	5/23	$40,000	105.160%	$2,064
Secured Medium Term Notes:					
	7.780%	7/30/02	$35,000	102.590%	$906
Pollution Control Revenue Bonds:					
	5.875%	8/08	$0	(1)	$0
Total Debt			$83,000		$3,116
Preferred Stock:					
	6.625%		$25,000	(2)	$0
Total Debt and Pref. Stk. to be repaid			$108,000		$3,116
Total Costs				USE	$3,100

(1) These bonds are non-redeemable until 8/1/03.

(2) Preferred Stock that helped support Montaup's capitalization is non-redeemable and would have to be tendered for, premium unknown at this time.

Wkp page 9 8

EASTERN EDISON - CAPITALIZATION
AFTER RECAPITALIZATION

SECURITIES	RATE	MATURITY	1999 ($000)	COST OF DEBT
First Mortgage and Collateral Trust Bonds:				
	5.875%	5/98	$0	
	5.750%	7/98	$0	
	6.350%	9/03	$0	$0
	6.875%	5/03	$40,000	$2,750
	8.000%	5/23	$0	
Secured Medium Term Notes:				
	7.780%	7/30/02	$0	
Pollution Control Revenue Bonds:				
	5.875%	8/08	$40,000	$2,350
Total Debt		6.38%	$80,000	$5,100
Preferred Stock:				
	6.625%		$5,000	
Total Debt and Pref. Stk. in Capitalization			$85,000	

Approximate Rate Base:			Debt	Equity
Distribution and Transmission @ EECO	$140,000			
Transmission @ MECO (EECO investment in MECO)	$20,000			
Approximate Rate Base / Capitalization	$160,000	50%	$80,000	$80,000

RVC ADJUSTMENT
R.I. ROE for 1998
($000)

Source: DTS WKP
p.

Description	Adjusted ROE	Filed ROE	Difference
Average Net Balance	$262,659	$262,659	
ROR	13.092%	11.338%	
1998 Return	$34,387	$29,780	
1998 Return on Unamort. ITC	1,426	1,235	
Total Annual Return	$35,813	$31,015	$4,798
		USE	$4,800

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SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)	SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039				
1998	379,752	123,473	256,280	262,659	29,781	1,235	31,016
1999	354,951	115,409	239,542	247,911	28,109	1,128	29,236
2000	325,106	105,705	219,401	229,471	26,018	1,020	27,038
2001	306,427	99,632	206,795	213,098	24,161	913	25,074
2002	278,924	90,689	188,234	197,515	22,395	806	23,200
2003	245,398	79,789	165,609	176,922	20,060	698	20,758
2004	206,203	67,045	139,158	152,384	17,278	591	17,868
2005	169,267	55,036	114,231	126,695	14,365	483	14,848
2006	127,001	41,293	85,708	99,970	11,335	376	11,711
2007	87,511	28,453	59,058	72,383	8,207	269	8,475
2008	41,723	13,566	28,157	43,607	4,944	161	5,105
2009	(0)	(0)	(0)	14,078	1,596	54	1,650

EECo 12/31/95
CAPITAL STRUCTURE

			ATWACC	BTWACC	
		11.4	× 5.52	=	9.09%
COMMON	48.45%	~~9.90%~~ (a)	~~4.46%~~	7.33%	
PFD	5.95%	9.83%	0.58%	0.96%	
LTD	45.60%	6.67%	3.04%	3.04%	
	100.00%		8.08%	11.338%	13.092%
TAX RATE			9.14%	39.225%	

COLUMN NOTES
(2) SEE SCHEDULE 1, P 13 COLUMN (4)
(3) SEE SCHEDULE 1, P 13 COLUMN (9)
(4) COLUMN (2) - COLUMN (3)
(5) COLUMN (4) PRIOR YEAR+COLUMN (4)/2
(6) COLUMN (5) x TOTAL RATE OF RETURN
(7) AVERAGE UNAMORT ITC (ASSUMING 12 YR SL AMORT OF P 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7)
(a) PER NEP RI FILING

BV30BAS2 WK4 10/23/97

SALE2.WK4 04/10/97

EECo SETTLEMENT FILING

MONTAUP ELECTRIC COMPANY

GENERATION PLANT IN SERVICE

AS FILED IN CTC

	PLANT IN SERVE 12/31/95	CANAL GAS CONV	ACCUM DEPR 12/31/95	NET PLANT 12/31/95	DEPR EXPENSE 1996	DEPR EXPENSE 1997	NET PLANT 12/31/97	GEN LAND	NET TAX BASIS 12/31/97
SOMERSET	57,175,297		29,143,212	28,032,085	2,157,981	2,157,981	23,716,122	657,767	14,805,188
CANAL	71,712,640	11,085,355 (2)	42,656,578	41,041,417	2,917,444	2,917,444	35,206,529		18,568,122
SEABROOK	194,734,485		24,029,107	170,705,378	4,877,709	4,877,709	160,949,959	97,491	19,575,066
MILLSTONE	178,230,927		40,481,944	137,748,083	4,734,998	4,734,998	128,276,988	46,616	3,950,578
WYMAN	4,049,794		2,019,505	2,030,289	112,584	112,584	1,805,120		154,686
NEWPORT DIESELS	4,486,494		2,683,816	1,802,678	152,092	152,092	1,498,404		911,766
BLACKSTONE HYDRO	0		0	0	0	0	0	0	
VERMONT YANKEE	8,854,413		5,088,286	3,766,127	346,545	346,545	3,093,036		1,005,044
MAINE YANKEE	14,929,907		7,490,842	7,439,065	867,040	867,040	6,104,965		2,195,234
PLANT HELD FOR FUTURE USE									
(LAND IN SOMERSET, MA)	604,405		0	604,405	0	0	604,405		604,405
(NET INV. IN SOMERSET 5)	5,859,846		0	5,859,846	(321,132)	(267,610)	6,448,588		2,827,000
(LAND IN PORTSMOUTH, R.I.)	216,055		0	216,055	0	0	216,055		216,055
NON-UTILITY PROPERTY (LAND IN PORTSMOUTH, R.I. AND DIGHTON, MA)	2,609,614		0	2,609,614	0	0	2,609,614		2,609,614
SETTLEMENT ADJUST.							(500,000)		(500,000)
TOTALS	543,463,677	11,085,355	153,573,290	401,875,842	15,645,282	15,898,794	370,031,898	801,898	67,922,760

Use $ 19,600

(2) BK DEPRECIATION RATE 3.53%.

ADD SOMERSET TRANSMIS	43,005,372	10,669,394
LESS NEWPORT DIESELS	(4,486,494)	(2,683,816)
LESS RETIRE WORK IN PROG		(162,555)
BLACKSTONE HYDRO	0	0
VERMONT YANKEE	(8,854,413)	(5,088,286)
MAINE YANKEE	(14,929,907)	(7,490,842)
NON-UTILITY PROPERTY	(604,405)	0
PLNT HLD FOR FUT. USE-SOM5	(5,859,846)	0
PLANT HELD FOR FUTURE USE	(2,609,614)	
SBK FUEL & MAT & SUP.	0	
MILLSTN FUEL & MAT & SUP.	0	
NEWPORT PLANT HELD	(216,055)	
CHECK WITH FERC FORM 1	549,606,515	157,837,185

TOTAL BOOK BASIS @ 12/31/97	370,031,898
TOTAL TAX BASIS @ 12/31/97	67,922,760
	302,109,138
EFF TAX RATE	39.225%
ACC. DEF TAX @ 39.225%	118,502,309

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EXHIBIT DTS-3

Retail Settlement Agreement

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Electric Utility Industry Restructuring	)))	D.P.U. Docket Nos. 96-100 and 96-24

RESTRUCTURING SETTLEMENT AGREEMENT

This Restructuring Settlement Agreement ("Settlement") is jointly sponsored by the Office of the Attorney General ("Attorney General"), the Division of Energy Resources ("DOER"), Montaup Electric Company ("Montaup"), and Eastern Edison Company ("Eastern"). The Settlement is designed to provide a resolution of issues presented in the industry restructuring Docket Nos. D.P.U. 96-100 (the Department's generic proceeding on electric utility restructuring) and D.P.U. 96-24 (Eastern's own restructuring proceeding). This Settlement, once approved by the Department, would require a restructuring of the EUA System in furtherance of the competitive market structure objectives of the Department and would implement *Consumers First* (the restructuring plan of the Attorney General) and the restructuring plan of the DOER as applied to Eastern and its affiliates in the EUA System. The Settlement includes a requirement for a filing by Montaup to separate its generation business from its transmission business, a voluntary commitment to divest Montaup's generation business through a sale or spinoff of 100 percent of that business, a request for approval of the jurisdictional separation between transmission facilities subject to the Federal Energy Regulatory Commission's ("FERC") jurisdiction and distribution facilities subject to the Department's jurisdiction, and the assurance of stranded cost recovery by Montaup and Eastern. This Settlement also resolves all ratemaking issues for Eastern and assures that Eastern's rates to retail customers comply fully with the requirements of *Consumers First* and the restructuring plan of the DOER. Finally, this Settlement resolves other issues necessary to implement retail choice for Eastern's customers on the Retail Access Date which is defined as the later of January 1, 1998 or the date when retail access is made available to all customers of the investor-owned electric utilities in Massachusetts.

The parties to this Settlement recognize and fully understand that their mutual promises in this Settlement evidence the consideration they have extended to each other in their efforts to settle the issues of D.P.U. 96-24 in accordance with the principles articulated in D.P.U. 96-100. The willingness and ability of Eastern and Montaup to commit to and fulfill any and all of their obligations under this Settlement, including in particular the full divestiture of Montaup's generating business, are predicated and conditioned upon the commitments by the Attorney General, DOER and the Department to the recovery in full of Eastern's and Montaup's stranded costs, as set forth in this Settlement and in the wholesale rate settlement included in Attachment 3. The Settlement is designed to implement *Consumers First* and the restructuring plan of the DOER in a manner that is consistent with the proposals articulated by the Department in its orders in D.P.U. 96-100. It is further designed to ensure recovery of Eastern's access charge as part of its transition from a fully bundled, completely regulated electric utility to an unbundled distribution company in an emerging competitive industry.

The Settlement follows the outline of *Consumers First*. The parties have agreed on the following:

I. Price Reductions for Customers

Consumers First requires meaningful price reductions for all customers on the Retail Access Date. A ten percent reduction represents the minimum acceptable result under *Consumers First* and is a predicate of the Settlement. The parties agree that the Settlement will include a ten percent reduction accomplished through the following principles:

> a reduction in cost recovery through the initial access charge as compared with currently effective rates; and
>
> a fixed stream of standard offer prices to customers provided by suppliers in the market that begin at 2.8 cents per kilowatthour and continue at escalating prices thereafter.

The combination of these principles in the Settlement, when applied to Eastern, will produce a base rate freeze prior to the Retail Access Date, implement unbundled rates for Eastern commencing on July 1, 1997, and provide retail delivery tariffs with a standard offer option on the Retail Access Date. Eastern's unbundled tariffs that will be effective until the Retail Access Date, together with the supporting documentation, are included in Attachment 1. Eastern's retail delivery tariffs with the standard offer option that will be effective on and after the Retail Access Date are included in Attachment 2. Eastern's retail delivery tariffs contemplate the corporate separation of Montaup's generation and transmission businesses and recognize that Montaup will be paid the transmission rates established by FERC.

Under a separate wholesale rate settlement included in Attachment 3, Montaup's wholesale Base Rates and Purchased Capacity Adjustment Clause factor ("PCAC") (Montaup Electric Company, FERC Electric Tariff, First Revised Volume No. 1) to Eastern will be frozen effective January 1, 1997 through the Retail Access Date, or through December 31, 2000 if the Retail Access Date has not yet occurred or Eastern has not otherwise terminated its all-requirements service under the wholesale tariff. Following the Retail Access Date, Montaup will cease providing Eastern all-requirements service under the wholesale tariff and Montaup will implement, and Eastern will pay, the contract termination charges set forth in that wholesale rate settlement.

The approval by FERC of the wholesale rate settlement is a condition to the effectiveness of this Settlement and to the provision of retail access by Eastern to its customers. Failure by FERC to approve the wholesale rate settlement as filed shall render this Settlement null and void and of no effect.

A. <u>The Unbundled Rates Effective from July 1, 1997 Through the Retail Access Date</u>

The unbundled rates included in Attachment 1 shall be phased in during the last six months of 1997 beginning on July 1, 1997 in accordance with the following terms:

1. Eastern's unbundled rates are divided into distribution charges, transmission charges, and generation charges. The distribution charges include Eastern's distribution costs including the conservation cost factors approved by the Department for calendar year 1996, and recovery of fixed costs currently recovered in Montaup's M-14 rate. The transmission charge includes transmission

costs billed to Eastern. The generation charge includes Eastern's fuel clause plus an allowance to approximate the variable costs currently associated with Montaup's purchased power expense recovered in Montaup's M-14 rate. Eastern's fuel clause will continue to operate as a fully reconciling charge during the effective period of the unbundled rates.

2. Eastern's unbundled rates will be used for billing purposes to provide information to customers.

3. Eastern will eliminate its Purchased Power Cost Adjustment ("PPCA") M.D.P.U. No. 245 as of January 1, 1997 and will roll PPCA into its base rates by adding the PPCA E-9R amount of ($0.00501) per kilowatthour and the PPCA E-11 reconciliation adjustment of $0.00096 per kilowatthour to base revenues. No further reconciliations of purchased power expense and revenues will be required after January 1, 1997, and any balance whether positive or negative will be retained or borne by Eastern and will not be refunded or collected from customers.

4. The unbundled rates shall remain in effect for all usage prior to the Retail Access Date, subject to Section I.C. below. The final balances in the fuel factor remaining after the Retail Access Date, whether positive or negative, shall be returned to or collected from customers in the first quarter after the Retail Access Date.

5. Eastern will eliminate its Conservation Cost Adjustment Clause ("CCA") M.D.P.U. No. 302 on January 1, 1997 and will roll CCA into its base rates by

adding the following amounts to base revenues:

R-1	$0.00174 per kWh
R-2	$0.00177 per kWh
R-3	$0.00205 per kWh
R-4	$0.00168 per kWh
G-1	$0.00434 per kWh
G-2/T-2	$0.00436 per kWh
G-4	$0.00409 per kWh
G-5	$0.00378 per kWh
G-6	$0.00370 per kWh
H-1	$0.00436 per kWh
H-2	$0.00368 per kWh
W-1	$0.00140 per kWh
A-6	$0.00355 per kWh

The roll in will provide $8,238,000 in annual base revenues.

6. Eastern will eliminate its Conservation Service Charge ("CSC") clause M.D.P.U. No. 182 on January 1, 1997 and will roll CSC into its base rates by adding the current CSC factor of $0.13 per customer-month to base rates. The roll in will provide $284,600 in annual base revenues.

7. Effective on July 1, 1997, Eastern shall close, or cease to offer, to new customers the following rate and rate riders:

   Large Primary Voltage Auxiliary General Service Rate A-6

   Economic Development Rate Rider ED

   Interruptible Load Rider ILR

B. <u>Retail Delivery Rates and the Standard Offer Effective from the Retail Access Date Through December 31, 2000</u>

The retail delivery rates included in Attachment 2 shall become effective for usage on and after the Retail Access Date on the following terms.

1. Eastern's retail delivery rates include four components. The distribution and access charges will be included in distribution charges, the transmission charge will be billed in a separate transmission service cost adjustment, and the standard offer charge will be billed separately to customers taking standard offer service. The four components are as follows:

   (a) Distribution charges that will remain in place through December 31, 2000 and which may be superseded by a filing that becomes effective after suspension on January 1, 2001. Performance standards are also established in the distribution component of the rate with credits to customers if the standards are not achieved.

   (b) Transmission charges that recover on a fully reconciling basis the transmission charges billed to Eastern by Montaup together with the charges, if any, billed to Eastern by or for the benefit of a Regional Transmission Group, an Independent System Operator, any other transmission provider, or any regional entity that may be created or allowed to implement rates and tariffs for transmission services or reliability related operating services under FERC accepted tariffs;

(c) Access charges that are designed to recover on a fully reconciling basis all contract termination charges paid by Eastern to Montaup. As set forth more fully below these access charges are fixed at 3.04 cents per kilowatthour for the period through December 31, 2000, subject to a residual value credit under Attachment 3, and at declining levels thereafter. The access charges are subject to adjustment for various factors included in Attachment 3.

(d) A standard offer for service during a transition period that is fixed for the period through December 31, 2004 subject only to a fuel index, which is on the following schedule:

Calendar Year	Price per kilowatthour
1998	2.8 cents
1999	3.1 cents
2000	3.4 cents
2001	3.8 cents
2002	4.2 cents
2003	4.7 cents
2004	5.1 cents

Together the charges in paragraphs (a) through (d) comply with *Consumers First* related to rates and prices. In addition, Attachment 4 contains revised terms and conditions for Eastern that reflect changes to Eastern's terms and conditions associated with its change to an unbundled distribution company, and which set forth the requirements for customers taking retail access. The details of each charge included in the rates and the changes to the terms and conditions are set forth in the paragraphs below.

2. Distribution Charges. The distribution charges in the retail delivery rates will become effective on the Retail Access Date and will remain in effect through December 31, 2000 on the following terms.

(a) Eastern shall be authorized to establish a storm fund to pay for all of the incremental costs of any major storm, defined as any storm with incremental costs of over $250,000 occurring after the date this Settlement is approved by the Department. The distribution component of the retail delivery rates contains a $1.3 million accrual for this charge and Eastern shall begin to accrue this amount to the fund on an annual basis commencing on the date when the retail delivery rates become effective. The accrual shall continue at $1.3 million per year until a modification is approved by the Department following a filing by Eastern. Eastern is authorized to charge all incremental costs of major storms against the fund and to pay or accrue interest on the fund balance whether positive or negative. The storm reserve fund will be prefunded with up to $2.0 million to the extent that such funds are available as excess recoveries resulting from the reconciliation of Montaup's 1996 PCAC billing rate.[1]

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[1] To the extent the PCAC refund to Eastern exceeds $2.0 million, any additional excess will be applied to offset the costs Eastern will incur to enhance its billing system to accommodate the billing of unbundled retail rates and competitive supplier services and to satisfy Eastern purchased power buyout costs. All PCAC refund proceeds in excess of the amounts necessary to establish the storm fund, to

(b) The retail delivery rates are based on the assumption that the dollar amounts associated with FAS 106 obligations related to retail operations, currently deferred on Eastern's books shall be amortized over the period commencing on January 1, 1997 and ending on December 31, 2000.

(c) This Settlement is based on the existing separation of distribution and transmission facilities on the integrated Montaup and Eastern systems, and thus assumes that all property owned by Eastern except for those facilities that are paid for by Montaup pursuant to FPC No. 15 is subject to the Department's ratemaking jurisdiction when it is used to provide access to retail customers. As set forth below, the parties agree that this separation is reasonable and appropriate, and should be approved by FERC and the Department for ratemaking purposes as part of this Settlement. However, approval of the jurisdictional separation of facilities without change is not a condition of this Settlement. Pending review of Eastern's and Montaup's facilities, Eastern and Montaup may seek to change the classification of certain facilities. In the event that facilities or costs are transferred from transmission to distribution or from distribution to transmission, the parties agree that appropriate adjustments to the transmission and distribution

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enhance the billing system and to satisfy purchased power buyout costs will be transferred to the Access Charge reconciling account and be reflected as a credit.

components of the rates will be made to reflect the transfer.

(d) The retail delivery rates are based on the assumption that all remaining unfunded state and federal FAS 109 deferred income tax balances [2] are recovered over three years after the effective date of the retail delivery rates.

(e) Eastern shall implement performance standards for reliability and customer satisfaction set forth in Attachment 6. Eastern shall be required to credit customers with an amount calculated in accordance with the schedules in that attachment during the year following any year that it failed to meet a performance standard. In addition, Eastern shall propose, by October 1, 1997, a performance standard for the effective management of line losses.

(f) Commencing on April 1, 1999 and by April 1 of each subsequent year, Eastern shall file with the Department to adjust rates to recover or refund revenues necessary to assure that Eastern's annual return on equity associated with distribution operations from the prior year averaged between six percent and eleven percent before any award or penalty that may be required pursuant to paragraph (e). Eastern's return on equity for

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[2] At December 31, 1996, deferred federal and state income tax balances were ($651,355) and $3,294,835 respectively. See Attachment 5.

the prior year will be determined by using the earnings available for common equity as reported to the Securities and Exchange Commission in Eastern's annual report adjusted to remove the impact of Eastern's investment in Montaup.[3] If Eastern's return on equity so calculated is below six percent, it shall be authorized to increase its rates by a uniform per kilowatthour surcharge calculated to provide sufficient revenues to increase Eastern's return on equity to six percent. If Eastern's calculated return on equity is above 11 percent, it shall be required to reduce its rates by a uniform per kilowatthour surcharge to refund revenues necessary to reduce the calculated return on equity between 11 and 12.5 percent by 50 percent and the earnings above 12.5 percent by 100 percent. If Eastern's calculated return on equity falls between 6 and 11 percent, then no further adjustment shall be authorized or required.

(g) Eastern shall also adjust its retail delivery rates for the effects of any changes in the federal or state income, revenue, sales, or franchise tax rates or laws, or any externally imposed accounting changes, if they affect Eastern's costs by more than $125,000 per year or any other charges under

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3 Eastern's earnings available for common equity and common equity balances shall also be adjusted to eliminate the effects of any writedown and to restore expenses associated with any such writedown that may result from the implementation of industry restructuring or this Settlement.

the retail delivery rates in Attachment 2.

(h) The retail delivery rates include fully reconciling charges for Eastern's access charges and transmission payments. The access charges shall be rolled into the distribution rates and shall not be shown separately on bills to customers. To maintain rate stability and avoid rate dislocations, cost allocations among rate classes were determined using the allocators for these cost functions that have been developed and approved in prior cases within continuity constraints.

(i) The discount for the R-2 Rate that is available for Eastern's low income customers is designed to reduce the base rates of a customer taking standard offer service by 35 percent in accordance with *Consumers First*. The discount is applied exclusively to the distribution component of the rate to assure that the same level of discount is available regardless of the supplier and to allow the operation of the reconciling access and transmission charges. The recovery of the discount from Eastern's other customers is based on distribution rate base in accordance with the practice in prior cases.

(j) Eastern's energy conservation services charge and conservation cost factors will be discontinued on the effective date of the unbundled retail rates. An overrecovery balance is anticipated which shall be placed in a reserve account to be used to mitigate the phased-in increase in the conservation and load management and renewables annual budgets for the period 1998 through 2001.

3. Transmission Charges. The transmission charges in Eastern's retail delivery rates shall be recovered in a uniform cents per kilowatthour factor per rate under the transmission cost adjustment provisions included in tariffs. The transmission cost adjustment shall recover the costs billed to Eastern by Montaup (or its successor or assignee), by any other transmission provider, and by other regional transmission or operating entities, such as NEPOOL, a regional transmission group ("RTG"), an independent system operator ("ISO"), or other regional body in the event that they are authorized to bill Eastern directly for their services. The transmission cost adjustment shall be established annually based on a forecast of transmission costs, and shall include a full reconciliation and adjustment for any over- or under-recoveries occurring under the prior year's adjustment. As set forth below, the Parties have agreed to support the implementation of NEPOOL reforms, including the formation of an RTG and ISO to the extent consistent with this Settlement. These reforms are desirable, but are neither a condition to retail access by Eastern nor of the approval of this Settlement.

4. Access Charges. The access charges in Eastern's retail delivery rates shall be recoverable in a uniform cents per kilowatthour factor under the access cost

adjustment provisions included in the tariffs in Attachment 2. The access cost adjustment factor will recover on a fully reconciling basis the contract termination charges billed by Montaup to Eastern under the wholesale rate settlement included in Attachment 3 and shall be subject to the dispute resolution procedures set forth in Section 3.5 of that wholesale rate settlement. The Parties agree that: a) the wholesale rate settlement in Attachment 3 is reasonable; b) approval of this Settlement by the Department represents express authorization of Eastern to pay those charges under G.L.c. 164, § 94A until Eastern's obligation to Montaup for payment of contract termination charges has been fully extinguished; c) the decision by Eastern to execute a contract termination agreement with Montaup included in Attachment 3 and to pay the contract termination charges is reasonable and prudent; and d) the contract termination charges shall be recoverable in Eastern's rates for retail delivery services for as long as the contract termination charges remain in effect.

5. Standard Offer. Consistent with *Consumers First,* Eastern shall arrange to provide standard offer service through a transition period ending on December 31, 2004, by putting out a bid for Standard Offer power supply. Backstop service would be provided by Montaup, its successor or assignee at the guaranteed wholesale price. If there is a simultaneous, statewide auction for Standard Offer service, Eastern will participate and take its pro-rata shares of bid services from the market and

backstop services from Montaup. Simultaneous statewide bid, in this context, would be a bid process accepted by all utilities offering Standard Offer service on the Retail Access Date under essentially the terms defined by *Consumers First* and representing at least 70% of Massachusetts electric load.

Standard offer service shall be available to all of Eastern's retail customers on the Retail Access Date. After the Retail Access Date customers are free to leave the standard offer at any time to purchase from an alternative supplier in the market but, once the market option is selected, a customer may not return to service at standard offer prices, provided, however, that standard offer service shall be available to all residential or Small General Service Rate G-1 customers who have previously taken service from an alternative supplier for the first year after the Retail Access Date, if such residential or Rate G-1 customer elects to return to standard offer service within 90 days of first taking service from the alternative supplier. The terms and conditions for the bids by potential suppliers for standard offer service are set forth in Attachment 7.

Eastern's standard offer prices are guaranteed, subject to the fuel price index described in Attachment 7. Under the tariffs included in Attachment 2, Eastern's charges for standard offer service are included as a separate surcharge to the rates for retail delivery service that apply to all retail access customers. Eastern shall reconcile the revenues billed to retail customers taking standard offer service against payments to suppliers of standard offer service and recover or refund any under or overcollection on the following terms:

(a) Any revenues billed by Eastern for standard offer service in excess of payments to suppliers of that service shall be accumulated in an account and credited with interest calculated using the methodology for calculating interest on customer deposits specified in Eastern's terms and conditions. The accumulated balance at the end of each calendar year shall be credited to all of Eastern's retail delivery customers through a uniform cents per kilowatthour factor in the following year.

(b) In the event that the revenues billed by Eastern do not recover Eastern's payments to suppliers or Eastern defers expenses to meet the inflation cap established in Section I.B.9, Eastern shall be authorized to accumulate the deficiencies in the account together with interest calculated as above and recover those amounts by implementing a uniform cents per kilowatthour surcharge on the rates for standard offer service, if and to the extent that the access charges billed by Eastern to its retail delivery customers are for any reason below the unadjusted contract termination charges listed in Attachment 3. Under-recoveries, if any, that remain after the standard offer transition period ends on December 31, 2004 shall be recovered from all retail delivery customers by a uniform surcharge not exceeding $0.004

per kilowatthour commencing on January 1, 2010.

6. Safety Net Service. In recognition that electricity is an essential service, and that there is a risk that in a competitive market some low-income customers may be unable to obtain or retain service on reasonable terms on account of a credit profile that would not create a barrier to service under the current regulated monopoly supply, Eastern shall arrange to provide electric supply for low-income customers who are no longer eligible to receive service under the standard offer and not adequately supplied by the market because they are unable to obtain or retain electric service from competitive power suppliers. Service under this provision shall be made available under rates, terms and conditions approved by the Department. Eastern shall fully recover any reasonable costs it incurs in arranging this service.

7. Basic Service. In recognition that customers may face an occasional hiatus between competitive suppliers, and in an effort to prevent such customers from losing power because they temporarily do not have a contractual relationship with a viable supplier, Eastern shall facilitate the continued delivery of power, such as by providing supply to such customers through the short-term wholesale power market, and allow for them to have a reasonable opportunity to make other supply arrangements, and shall fully recover its reasonable costs of providing such service. Such supply shall be provided on terms and conditions approved by the

Department.

8. Terms and Conditions. Eastern's terms and conditions in Attachment 4 have been modified to reflect the changes in Eastern's operations. In addition to modifications that are necessary to reflect changes to Eastern's business with its customers, the terms and conditions in Attachment 8 have been added to specify the terms and conditions for the settlement process with suppliers. Those requirements are designed to allocate load and resources as required under the NEPOOL agreement and protocols. These terms and conditions are recommended by Eastern for approval by the Department. However, approval is not a condition of the Settlement.

9. Inflation Cap for Standard Offer Customers. Eastern shall assure that the economic value of the ten percent rate reduction for customers is maintained by capping average revenues per kilowatthour for retail delivery service plus the standard offer, adjusted to exclude: (1) the fuel price index in Attachment 7; (2) any adjustments caused by the return on equity floor under Section I.B.2(f); and (3) changes in tax laws or accounting under Section I.B.2(g), at 9.15 cents per kilowatthour adjusted for the Consumer Price Index occurring between October 1, 1996 and the effective date of any adjustment to the standard offer price under Section I.B.1(d). Eastern shall defer expenses associated with payments to vendors under the standard offer equal to the amount necessary to meet the

inflation cap and recover such deferral using the mechanism in Section I.B.5(b).

C. Right to File for Rate Change in the Event that Retail Access Date Postponed

Nothing in this Settlement shall prevent the Parties from seeking a rate change to become effective after suspension on January 1, 2001 in the event that the Retail Access Date has not occurred by that time.

II. Benefits of Competition Extended to All Customers

Consumers First requires utilities to extend the benefits of competition to all customers. This Settlement achieves that requirement by providing all customers with the opportunity to choose alternative suppliers on the Retail Access Date and by guaranteeing significant rate reductions for customers who take standard offer service prior to choosing an alternative supplier under the ratemaking portion of this Settlement.

This Settlement further requires Eastern to provide retail access and implement retail delivery rates on the Retail Access Date. Under this Settlement, this condition will be achieved when legislation, final regulatory or court action, or unchallenged settlements approved by the Department in a final order with all other investor-owned utilities are in place. In the event that retail access is not yet available to all customers of investor-owned utilities by January 1, 1998, Eastern in its sole discretion shall have the option to file for the Department's approval to accelerate the Retail Access Date under this Settlement, implement retail access for its customers, and make the tariffs in Attachment 2 effective by providing the Department and the Parties with 90 days advance notice in writing.

III. Protect the Environment and Promote Conservation.

The third element of *Consumers First* requires the restructuring plans of utilities to protect the environment and promote conservation. This Settlement complies with these requirements by requiring significant emissions reductions from Montaup's owned generating facilities located in Massachusetts and by continuing funding for demand-side programs including clean renewable resources. The Parties have agreed to the following terms:

A. Emissions Reductions.

Montaup or its successors in interest shall reduce emissions of NO_x and SO_2 from its Somerset Station and its share of Canal No. 2 by the amounts and on the schedule and terms set forth in Attachment 9.

Nothing in this Settlement shall affect Montaup's obligations to comply with environmental regulations lawfully imposed or restrict the environmental regulators' authority to impose new environmental standards.

B. Conservation and Load Management and Renewables.

By August 1, 1997, Eastern shall develop and file with the Department annual budgets for demand-side ("DSM") programs and clean renewables for the period 1998 through 2001 based on the following rates per kilowatthour[4].

Calendar Year	Mills per kWh	Annual Budget
1998	3.25	$ 8,450,000
1999	3.55	9,230,000
2000	3.85	10,010,000
2001	4.00	10,400,000

An overrecovery balance of $4,182,899 at January 1, 1997 shall be placed in a reserve account to be used to mitigate the phased-in increase in the conservation and load management ("C&LM") and renewables annual budgets throughout the period 1998 through 2001. Unexpended budgeted amounts from 1997 for DSM and/or renewables shall be used to support collaborative research on market transformation and other DSM issues[5]($100,000 to be supplied early in 1997) and to prefund the 1998 renewables amount as of January 1, 1998. At least 15 percent of the annual C&LM budget shall be spent on residential programs. At least 15 percent of the amount

[4]During any given year, Eastern shall reconcile actual spending, actual kWhs distributed times specified mill levels and Lost Base Revenue to the budgeted expenditures, with separate reconciliations for DSM and renewables, and shall carry forward any balance, positive or negative, into a reserve account to adjust program budget levels for the following year. The parties agree to work collaboratively to ensure that actual expenditures in 1998-2001 deviate from specified mills/kWh amounts as little as possible.

[5]The collaborative would include signatories and others interested in developing and implementing DSM and/or renewables plans.

budgeted for residential programs in any given year shall be spent on low income residential programs, and the amount budgeted for low income residential programs implemented through the existing weatherization and fuel assistance program network shall be a minimum of $148,000 in 1998, $175,000 in 1999, $188,000 in 2000, and $202,000 in 2001, provided that the performance of network contractors is of satisfactory quality to Eastern. For each of the following years listed below, funds shall be allocated within the annual budgets to commercialize and develop fuel cells and a diverse group of clean renewables in a manner approved by the Department, with collaborative input, based on the following rates per kilowatthour times the kilowatthours distributed by Eastern.

Calendar Year	Mills per kWh	Estimated Funds Available
1998	0.25	$ 650,000
1999	0.55	1,430,000
2000	0.85	2,210,000
2001	1.25	3,250,000

The budgets shall also include expenditures, for the ECS program, Lost Base Revenues, expenditures for Eastern's demand-side management programs, a collaborative or collaboratives on energy efficiency and renewables, sophisticated metering and control systems, and overhead costs. The cost of sophisticated metering and control systems will not exceed $800,000 over the period January 1, 1998 through December 31, 2001 and will not exceed $400,000 in any given calendar year.

Eastern will make every effort to invest in cost-effective C&LM and renewables.

However, because of the maturity of its C&LM effort, the relative high cost of new technologies that will be targeted in market transformation initiatives, and the relative immaturity of renewables technologies, Eastern may invest in some C&LM and renewables that do not pass individual benefit-cost analyses.

While the Department will decide the appropriate level for ongoing conservation, load management and renewables funding after December 31, 2001, Eastern, the Attorney General, and DOER jointly recommend that evaluation of funding after this date be informed by review of the then current market barriers and experience gained with the competitive energy markets and customer choice established in this Agreement, and should further be based upon environmental and economic goals to be achieved by such funding established by the Department through appropriate proceedings. Ongoing commercialization support for fuel cells and clean renewable technologies beyond December 31, 2001 should also be based on a goal of supplying at least four percent of Massachusetts electricity kilowatthour sales from such new, clean technologies by the end of 2007.

Generation technologies potentially eligible for commercialization support, subject to Department review, shall include a diverse group of low and zero emissions generation technologies with substantial long-term, cost-effective regional production potential which utilize any of the following:

a) solar photovoltaic and solar thermal electric energy;

b) wind energy;

c) ocean thermal, wave and/or tidal energy;

d) fuel cells;

e) landfill gas; and

f) low emission advanced biomass power conversion technologies like gasification using such biomass fuels as wood, agricultural, or food wastes; energy crops, biogas, or organic refuse-derived fuel.

While the Department will decide how funds shall be allocated based on input from a collaborative process, the commercialization of clean generating technologies should be accomplished in a least cost manner through an appropriate competitive bidding process. Optimal use should be made of competitive bidding in funding commercialization activities. Commercialization activities shall also attempt to promote as diverse a group of clean technologies as is practical and ensure no single resource or technology dominates commercialization efforts.

Eastern will support pilot projects in 1997 through a collaborative or collaboratives on energy efficiency and renewables funded out of the budget for cost of conservation and load management approved by the Department for 1997 to assess candidate renewable technologies, their costs and where they make sense, and conservation and load management technologies that can be used in reducing or avoiding distribution system costs. Operational procedures to invest in clean distributed generation and geographically-targeted DSM that lower distribution service costs should be implemented as soon as is practical.

Clean distributed generation of 30 kilowatts or less which include fuel cells, renewables and small scale cogeneration shall remain eligible for "net metering" as provided for in existing Department regulations regarding the buy-back of generating power at the retail rate.

IV. <u>Protect Low Income Customers.</u>

The fourth principle in *Consumers First* focuses on the continued protection of low income customers. Eastern's plan complies with this principle by continuing the low income discount Rate R-2 to provide customers taking standard offer service the same 35 percent discount on the base rate as presently received. The discount shall be applied exclusively to the distribution component of the rate to assure the same level of discount regardless of the supplier and to allow operation of the reconciling access and transmission charges. The recovery of the discount from Eastern's other customers is based on distribution rate base in accordance with the practice in prior cases.

In order to protect against redlining by suppliers, Eastern will create an option under which suppliers can bill Eastern Edison directly for electricity delivered up to the prices for Standard Offer Service for Rate R-2 customers, and Eastern will assume all credit risks including the risk of non-payment, associated with these customers.

Electric service is essential and should be available to all customers. The restructured electricity industry should provide adequate safeguards to assure universal service. Programs and mechanisms that enable residential customers with low incomes to manage and afford essential electricity requirements will be maintained throughout the period of the settlement in order to foster the goal of universal service.

V. Create a Fully Functioning Stable and Reliable Structure for the Competitive Market.

The final principle in *Consumers First* focuses on the institutional structure and protections necessary to prevent unfair and anti-competitive conduct, and to maintain reliable and safe electricity supplies. These industry structure issues focus on the region as a whole and the corporate structure of Eastern and its affiliates within the EUA System.

A. Regional Reform.

The regional issues center on the formation of a regional transmission group, an independent system operator and NEPOOL reform. Eastern and Montaup have participated actively in these issues. Montaup and Eastern shall continue to support regional reform and shall consult with the parties to this Settlement to develop mutually agreeable approaches to the issues that are consistent with the terms of this Settlement. However, this Settlement is not conditional upon the adoption, approval, or implementation of the filed NEPOOL proposal.

B. The Jurisdictional Separation Between Transmission and Distribution.

In Order 888, FERC set forth a seven factor test for determining whether facilities used to provide access to retail customers are subject to the ratemaking jurisdiction of FERC under the Federal Power Act or of the Department under state law. Attachment 10 provides a specific evaluation of FERC's seven factors as applied to the separation of facilities between Eastern and Montaup. The parties agree that all of Eastern's facilities, except for those that are paid for by Montaup pursuant to FPC No. 15, meet FERC's seven factor test for designation as distribution facilities subject to the Department's jurisdiction, and the parties support an affirmative recommendation by the Department to FERC that the current separation between the transmission facilities owned by Montaup and distribution facilities owned by Eastern be adopted by FERC for ratemaking purposes as part of the approval of this Settlement. However, approval of the jurisdictional separation of facilities without change is not a condition of this Settlement.

C. Transfer of Transmission Properties and Facilities.

Montaup shall develop and file with the Department by July 1, 1997 to separate its generating business from its transmission business.

D. Divestiture of Montaup's Generating Business.

1. Consistent with the restructuring plan advanced by the DOER, Montaup agrees, subject to the receipt of all required governmental approvals, to lease, sell, spin off, or otherwise dispose of its generating business to a nonaffiliated entity or entities, other than properties, assets, and entitlements classified to be the transmission function. The parties intend that the properties to be divested shall also include properties currently in FERC Account 105 Land Held for Future Use and FERC Account 121 Nonutility Property. Montaup shall develop and file by July 1, 1997 a plan with the Department to implement divestiture. This plan shall include in particularized detail the generating business to be divested and shall be updated with an informational filing 90 days before the date of divestiture. The Department shall review the plan and shall issue a final order on the method of sale and the

reasonableness of the proceeds as part of its plan approval. The divestiture shall be completed by six months after the later of the Retail Access Date or the receipt of all governmental approvals necessary for the transfer. If, for any reason, the divestiture is not completed within three years of the Retail Access Date, Montaup shall file a report with the Department explaining the delay.

2. As part of the divestiture, Montaup will endeavor to sell, lease, assign, or otherwise dispose of its minority shares of nuclear units on terms that will assign ongoing operating costs and responsibility to a nonaffiliated third party but may require Montaup to retain the obligation for post-shutdown, decommissioning, and site restoration for these units. Montaup shall recover these post-shutdown, decommissioning, and site restoration costs from Eastern through the contract termination charge, and shall credit any net positive value or recover any payments associated with such transaction in the Reconciliation Account of the contract termination charge. The Parties agree that this approach is reasonable and Montaup is authorized to include it in its divestiture plan. This plan will be subject to approval of the Nuclear Regulatory Commission ("NRC") to the extent required by NRC regulations. In the event that Montaup is unable to sell, lease, assign, or otherwise dispose of its nuclear units, Montaup shall include 80 percent of the going forward costs of operating the units, including variable costs and capital additions, and 80 percent of the revenues from sales of energy and capacity from

such units, in the Reconciliation Account and recover or return any difference through its contract termination charges to Eastern. Within six months prior to implementing the Performance Based Rate set forth in the prior sentence, Montaup will consult with the parties on a performance standard for nuclear safety indicators and will file such performance standard with a maximum potential credit for nonperformance of $250,000. Montaup's sales, if any, from its nuclear units shall not be made directly to retail customers of Eastern and may be used by Montaup to fulfill its backstop obligations under the standard offer.

3. As part of the divestiture, Montaup will endeavor to sell, assign or otherwise dispose of its power contracts on terms that will assign ongoing contract payments to a nonaffiliated third party. In that event, changes to the above market payment to power suppliers shall be reflected in the Reconciliation Account. In the event that such contracts cannot be sold, assigned, or otherwise disposed of, the power purchased from those contracts shall be sold and the contract payments and market value associated with the sale shall be reflected in the Reconciliation Account. Such sales, if any, shall not be made directly to retail customers of Eastern and may be used by Montaup, to fulfill its backstop obligations under the standard offer. Nothing in this Settlement shall affect the rights of suppliers or Montaup under purchased power contracts.

4. In this proceeding, the Department and intervenors have expressed the goals of

attaining a market valuation of utility stranded costs and creating a competitive market for supplying electricity to consumers. The Department has expressed a preference for voluntary divestiture of utility generation as a means of achieving these goals. The Department has stated that is "has the authority to approve the voluntary divestiture of assets," but that it has "no explicit statutory authority [to] order divestiture, nor is it likely to be implied." (D.P.U. 95-30, August 16, 1995). Montaup and Eastern have asserted that the Department lacks authority to order divestiture, and would contest any effort by the Department to do so. Montaup and Eastern have agreed, as part of this Settlement, voluntarily to undertake such divestiture. In exchange, and as consideration for this voluntary divestiture, the parties to this Settlement, and the Department by its approval of this Settlement, agree that Montaup's contract termination charges as set forth in Attachment 3 to Eastern and Eastern's access charges as set forth in Section I.B.1(c) for the period contemplated by this Settlement are just and reasonable. Accordingly, and to give effect to the reliance placed by the parties on the foregoing, the Department shall treat the findings that such contract termination charges and access charges are just and reasonable as a final determination made after public notice and a full investigation of the merits, and, in any future proceeding brought by any person or party, or by the Department on its own motion, shall accord such finding the full benefit of policies of repose including, without limitation, the applications of the doctrines of res judicata, collateral estoppel, the filed rate doctrine, the prohibition against retroactive ratemaking, and the finality of contracts, it being the express intention of the parties to prevent, as a matter of law and policy, the Department or any other authority from: (a) revisiting the issue of the justness and reasonableness of the contract termination charges and the access charges; (b) reducing, other than as set forth in Attachment 3, the amount of the contract termination charges or the access charges; or (c) otherwise limiting the right of Montaup, its successors or assigns, or Eastern to charge and recover the contract termination charges or the access charges set forth in this Settlement for any reason prior to their recovery in full as contemplated by this Settlement.

5. To facilitate the divestiture and valuation of Montaup's units, the parties agree that it is in the public interest for Montaup or its successors or assigns to be authorized to sell electricity at market prices in either the wholesale or retail markets, and that Montaup or its successors or assigns shall be free to apply to become an exempt wholesale generator pursuant to Section 32 of the Public Utility Holding Company Act of 1935 and other Federal law, rules and regulations, and to designate each and every generating facility and entitlement it owns as an eligible facility pursuant to that statute. Approval of this Settlement by the Department shall represent express findings by the Department that it has sufficient regulatory authority, resources, and access to books and records to exercise its duties, and that the full

participation of Montaup in the market and the designation of each of its facilities as eligible facilities will benefit consumers, is consistent with existing state laws, will not provide any unfair competitive advantage by virtue of its status as a facility owned or formerly owned by Montaup, and is in the public interest.

Nothing in this Settlement shall prevent affiliates of Montaup from re-entering the generation business following the completion of divestiture, and nothing in this Settlement shall prevent affiliates of Montaup from marketing electricity, other energy sources, or energy services to customers within or outside Eastern's service territory.

E. Customer Service Standards

Minimum residential customer service safeguards and protections for consumers in their dealings with competitive power suppliers, as provided by statute or the rules of the Department, should be maintained.

VI. Successors and Assigns

The rights conferred and obligations imposed on any Signatory by this Settlement shall be binding on or inure to the benefit of their successors in interest or assignees as if such successor or assignee was itself a Signatory hereto.

VII. Additional Provisions.

A. This Settlement is the product of settlement negotiations. The content of those negotiations shall be privileged and all offers of settlement shall be without prejudice to the position of any party or participant presenting such offer.

B. Except as expressly set forth above, this Settlement is submitted on the conditions that it be approved in full by the Department and that FERC approve in full the wholesale rate settlement included in Attachment 3 and on the further conditions that if the Department does not approve the Settlement in its entirety or FERC does not approve the wholesale rate settlement in its entirety, the Settlement shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or used for any purpose.

C. Acceptance of this Settlement by the Department shall not be deemed to restrain the Department's exercise of its authority to promulgate future orders, regulations or rules which resolve similar matters affecting other parties in a different fashion provided, however, that approval of this Settlement by the Department shall represent an express grant by the Department of a waiver for Eastern and Montaup of any rule, requirement or regulation promulgated by the Department under existing statutes as part of its proceeding on utility restructuring that are inconsistent with the terms of this Settlement and the wholesale rate settlement. Nor shall this Settlement be deemed to restrain the authority of the General Court to enact any law which would resolve the matters covered by this Settlement in a different fashion.

D. The Department approval of this Settlement shall endure so long as is necessary to fulfill this Settlement's objectives. In the event of future regulatory actions other than actions required by legislative actions taken prior to the Retail Access Date or legislative actions after the Retail Access Date which may render any part of this Settlement ineffective, Eastern and Montaup shall nevertheless be held harmless and made whole through rates to Eastern's customers.

IN WITNESS WHEREOF, each of the Signatories has executed this Agreement intending to be bound by its terms.

Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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for

SCOTT HARSHBARGER
ATTORNEY GENERAL

May 16, 1997

Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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May 16, 1997

Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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May 16, 1997

Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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May 15, 1997

Electric Utility Restructuring
Settlement Agreement

DPU Docket Nos.
96-100
96-24

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May 16, 1997

Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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May 15, 1997

Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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May 15, 1997

Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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May 5, 1997

Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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Electric Utility Restructuring
Settlement Agreement

D.P.U. Docket Nos.
96-100
96-24

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May 15, 1997

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May 6, 1997

EXHIBIT DTS-4

Eastern Edison

Transition Cost Adjustment Clause Tariff

EASTERN EDISON COMPANY
TRANSITION COST ADJUSTMENT CLAUSE

The Transition Cost Adjustment shall be a pass through of the cents per kilowatthour termination charge that Montaup Electric Company ("Montaup") bills to Eastern Edison Company ("Company"). The initial termination charge shall be incorporated within the Transition Charges established for each rate class and distributed among the several components thereof at a level equivalent to $0.03040/kWh through December 31, 2000, subject to adjustment for the Residual Value Credit allowed by the Federal Energy Regulatory Commission upon the divestiture of Montaup's non-nuclear generating facilities as they occur. Thereafter, the Transition Charges for each rate class shall be adjusted by applying an Adjustment Multiplier each time that the termination charge Montaup bills to the Company changes. The Adjustment Multiplier to be applied to the Transition Charges for each rate class shall be determined by:

1. Calculating the expected revenues from the application of the new termination charge for the period during which the Adjustment Multiplier will be in effect;

2. Calculating the actual revenue difference between the termination charges paid and the Transition Charge revenues received during the period beginning with the effective date of the initial termination charge and ending with the effective date of the new termination charge;

3. Dividing the sum of the foregoing revenues by the initial termination charge revenues calculated for the period during which the Adjustment Multiplier will be in effect.

The Adjustment Multiplier shall be expressed to five decimal places.

The initial Transition Charges for each rate class are as follows:

RATE		TRANSITION CHARGE	
R-1	Energy Charge	$0.03040	per kWh
R-2	Energy Charge	$0.03040	per kWh
R-3	Energy Charge	$0.03040	per kWh
R-4	Peak Energy Charge	$0.14406	per kWh
	Off-Peak Energy Charge	$0.01154	per kWh
G-1	Energy Charge	$0.03040	per kWh
G-2	Demand Charge	$8.04	per kW
	Energy Charge	$0.00262	per kWh
G-4	Demand Charge	$7.99	per kW
	Peak Energy Charge	$0.01788	per kWh
	Off-Peak Energy Charge	$0.00978	per kWh
G-5	Demand Charge	$6.33	per kW
	Peak Energy Charge	$0.01743	per kWh
	Off-Peak Energy Charge	$0.01014	per kWh

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dated February 20, 1998.

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G-6	Demand Charge	$6.33	per kW
	Peak Energy Charge	$0.02219	per kWh
	Off-Peak Energy Charge	$0.01490	per kWh
T-2	Demand Charge	$8.32	per kW
	Peak Energy Charge	$0.02031	per kWh
	Off-Peak Energy Charge	$0.01221	per kWh
A-6	Demand Charge	$6.45	per kW
	Peak Energy Charge	$0.01433	per kWh
	Off-Peak Energy Charge	$0.00714	per kWh
H-1	Energy Charge	$0.03040	per kWh
H-2	Energy Charge	$0.03040	per kWh
W-1	Energy Charge	$0.03040	per kWh
S-1	Energy Charge	$0.03040	per kWh

Each adjustment of the Transition Charges for the Company's applicable rates shall be in accordance with a notice filed with the Department of Telecommunications and Energy ("the Department") setting forth the amount of the adjustment. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Department may authorize.

The operation of this Transition Cost Adjustment clause is subject to Chapter 164 of the General Laws.

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